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Engineering Analysis of Olympic Pipe Line Company's Safety and Risk Mitigation Features for Application No. 96-1 Cross Cascade Pipeline Project

Charles H. Batten, President, P.E., BCE,MSS
Batten & Associates, Inc.
HC75 Box 2201
Locust Grove, Virginia 20508

540-972-2002
FAX 540-972-0275
e-mail: battenc@erols.com

EXHIBIT CHB-3

GENERAL

The Cross Cascade Pipeline Project, as detailed in Olympic Pipe Line Company's "Application Number 96-1 for Site Certification," revised May 1, 1998, is a general discussion on the proposed pipeline giving few specifics about the standards to be applied for construction and operation. The proposal shows that the pipeline and system design is typical of cross country hazardous material transportation pipelines that have been in operation for several years and whose adequacy for public and environmental safety has been often called into question.

The use of a standard design for a pipeline that proposes to traverse through 78 wetlands and adjacent to 59 others and cross 293 waterways is not compatible with the potential for harm that can result in the event of rupture or undetected leakage. The Application includes several misleading and inaccurate statements as incentives for approving the application while failing to address the higher risk for catastrophe posed by pipeline transportation over other transport means. No amelioration measures are included sufficient to offset the higher risk posed.

PRODUCT RELEASE

Rupture. - The transportation of hazardous liquids by pipeline provides an economical transportation means to supply the large quantities of fuels needed to sustain the quality of life for communities. However, the information in the application is insufficient to demonstrate that this pipeline would necessarily improve human and environmental safety over other transportation means. A maximum release from an individual highway transport tank would be limited to the tank capacity, generally about 8,000 gallons according to OPL. A rail car release would be limited to about 25,000 gallons. The quantity of product released from the largest of the barges used to transport fuel, on the Columbia River (65,000 BBL [2.73 million gallon]) likely would be limited to a volume no greater than its largest compartment, but information on that volume was not provided. The largest likely release quantity from barge transports would be less than the quantity contained in the largest storage compartment for double-hull barges.

In contrast, should the pipeline rupture while flowing at its maximum rate of 7,500 BBLs/hour (315,000 gallons/hour), 5,250 gallons per minute of hazardous liquid product would be released under pump pressure from the upstream pipe into the environment whether that environment be wetlands, rivers, or communities. Hazardous liquid product would also be released at a lesser flow rate from the downstream pipe. The release rate under pump pressure would continue until the release was detected and the pumps shutdown. Afterwards, albeit at a lesser rate, product would continue to flow from of the pipeline until the nearest upstream and downstream valves were closed and gravity flow from the isolated section ceased.

Depending on sensitivity, timeliness for detection, and reliability any installed leak detection system; the effectiveness of the pipeline controller; and the type of valve operation possible, the quantity of hazardous liquid product released into the area due to a pipe rupture may be as little as 20,000 gallons (the equivalent of more than 2 tank trucks or about one tank car for the same volume) or ½ million or more gallons (the equivalent of more than 62 tank trucks or 20 tank cars for the same volume).

The application speaks of various savings that may be achieved by displacing barge, highway, and rail transportation of hazardous petroleum liquids; however, it does not identify and address the substantial risks that will added to properties adjacent to the pipeline and to sensitive environments along the pipeline route. Also, the application does not show how these increased risk are to be remedied to acceptable levels through the design of the pipeline and the controls employed.

Leak. - The system for monitoring the operations of the pipeline and its leak detection subsystem are not detailed as their ability is to detect and identify the location of leaks when the pipeline is operating at maximum design flow. No information is provided as to minimum leak rate detectable, the time interval for detecting the specific leak rate, the reliability for detecting the specified leak rate, nor the precision of the system to identify the location of an identified leak. Petroleum products leaking from a pipeline (the most common incident occurrence) may go undetected for many hours and if the leak is small, may go undetected for days or months. Those undetected leaks can migrate to contaminate wetlands, soils, ground water, and surface waters. According to Dr. Jim C. P. Liou a study for the American Petroleum Institute[1], one to five percent of the fluids transported through the pipelines are lost and are not detectable by monitoring systems in use.

Even when petroleum product leaks are rapidly detected, the released liquids can still do irreparable harm to the environment by contaminating the soil, nearby waters, and sensitive environmental areas, such as estuaries and low-lands, and result in fish and wildlife kills. The extent such damage will occur is dependent greatly on the pipeline operator's capacity to rapidly detect and shutdown the pipeline system, promptly isolate the area of leakage from the remainder of the pipeline, and respond to the release area to stop product outflow and initiate product removal and clean up.

The pipeline industry's primary means for detecting leaks is making periodic comparisons of input versus output and making comparisons over time of total input versus total output, e.g. 24-hour time intervals. Today's mass/volume computerized samplings of the pipeline product inventory, while being performed at ever shorter time intervals and being compared over longer time periods, still are unable to detect small leaks or to identify the leak location. Even should one accept the applicant's detection claim for the proposed system, its stated ability is to detect leaks of about one percent (1%) of the flow rate - **at the maximum design capacity that 1% leak is equal to 3,150 gallons per hour.**

This type leak control capability contrasts unfavorably with the advances made for protecting the environment in other areas. As examples, (1) some pipeline leak detection subsystems have been shown to be capable of detecting leaks of less than 0.1 percent of flow from pipelines more than 400 miles in length operating at capacities over 11,000 BBLs per hour,[2] (2) some pipeline segments are constructed of double-wall pipe, (3) barges tank levels are being monitored to immediately detect leakage and barge vessels are being fitted with double hulls to prevent tank ruptures in the event of grounding or other events that may damage the vessel's hull, (4) petroleum fuel storage tank facilities are being monitored to immediately detect small leaks and are equipped to prevent spilled products from contacting the ground, and (5) metal service station fuel storage tanks are be replaced with non-corrosive tanks and the installation is monitored for leaks. While some pipeline operators have kept up with technological advances for minimizing the potential for releases and for prompt detection of small spills, the petroleum

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1 Liou, J.C.P., C.G. Brockway, and R.B. Miller 1992. "Pipeline Variable Uncertainties and Their Effects on Leak Detectability." American Petroleum Inststute Symposium, Houston, Texas, April 8-9, 1992.

2 Farmer, Edward J., Proceeding of the 1989 American Petroleum Institute Pipeline Conference, "A new approach to pipe line leak detection," Sacramento, California.

pipeline industry as a whole needs to move forward by incorporating the best of available technologies for preventing leakage, monitoring their systems to prompt detect potentially hazardous releases, and developing means to limit the quantity of petroleum products released, especially in environmentally sensitive areas.

Some undetected leakage over time from the Cross Cascade Pipeline, as proposed, is inevitable due to inaccuracies in its measurement equipment, the lack of sensitivity of its leak detection subsystem and the type of transportation operations involved. The result of the leak detection subsystem insensitivity for this pipeline means that the capacity of one tank truck might leak into the ground every three hours without being detected. Even after such a leak is discovered through visual or other means, it will require weeks and a major cleanup effort to remove released petroleum products and contaminated soils and to then restore water quality. Nothing will be able to replace fish and wildlife killed as a result of a spill. After cleanup operations are complete, distinct and repugnant odors will remain and it will require years before vegetation and recreational uses can be restored.

REGULATIONS AND ENFORCEMENT

The regulation, inspection and enforcement for liquid pipelines nationally rests primarily with the Office of Pipeline Safety, Research and Special Programs Administration, U.S. Department of Transportation (OPS). The Federal government preempted state regulation of interstate liquid pipeline operators; however, for this intrastate pipeline, the State, as long as certified by the OPS, may issue its own safety regulations for intrastate liquid pipelines so long as they are compatible with and at least as stringent as the Federal pipeline safety requirements. Under certification, the State may perform regulatory oversight. The State of Washington chose to adopt, unchanged, the Federal regulations for liquid pipelines, 49CFR195 and 49CFR199.

Liquid Pipeline Safety Regulations**. -**"Federal safety regulations cover three broad areas: (a) design, construction, operation, and maintenance of pipelines; (b) testing and inspection of lines, including corrosion control; and (c) operator reporting requirements,"[3] The initial regulations of the OPS incorporated the provisions of the ASME Code for Pressure Piping, B31.4 Code, which was developed by the liquid pipeline industry under the sponsorship of the American Society of Mechanical Engineers. That code formalized into recommendations those procedures and practices of the liquid pipeline industry that could be agreed upon by all committee members. Because of the committee procedural practices at the time, any member could prevent inclusion of a procedure or practice not agreeable to his company. The Federal regulations have changed little since their inception. Special Report 219[4] points out that liquid pipelines are exempt from Federal routing and environmental assessment requirements and these aspects are subject to the individual state requirements.

Until 1994, when the U.S. Congress required the OPS to consider environmental impacts of pipeline leaks and ruptures, the OPS was required only to consider public safety in the development of its regulations. Even with this new mandate, the OPS has not performed a review of its regulations to determine what modifications must be made to limit to a reasonable level the potential of liquid pipelines for contaminating and degrading water bodies, soils, and the environment in general.

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[3] Special Report 219 "Pipelines and Public Safety," Transportation Research Board, National Research Council, 1988.

[4] Special Report 219, "Pipelines and Public Safety," Transportation Research Board, National Research Council, 1988, pp. 65-67.

The OPS regulations for liquid pipelines (49CFR195) are applicable to the transportation of hazardous liquids (petroleum, petroleum products including highly volatile products such as liquefied petroleum gases, and anhydrous ammonia), and carbon dioxide. The regulations are not based on risk potential: they are a compilation by the liquid pipeline industry of the provisions that it is willing to have imposed upon itself. As noted by the National Transportation Safety Board (NTSB), "…the procedures of analysis under the concepts of 'System Safety' [risk analysis and risk management] have not yet been adopted by in the surface modes of transportation. Pipeline systems have the greatest susceptibility to advantages derived from a systematic approach to ensure an optimum degree of safety of operations. This is because pipelines are definable as engineering systems and may, therefore, be subjected to a higher degree of control than other modes of surface transportation to identify hazards and refine risks."[5] Unfortunately, not much in the liquid pipeline design and safety requirements has changed since the NTSB addressed the need for improved identification and control of pipeline safety hazards and no action has occurred by the OPS for identifying and controlling the hazards posed to the environment by liquid pipelines.

Under the OPS regulations, a liquid pipeline can be used to transport hazardous liquids, highly volatile liquids such as liquefied petroleum gases, or carbon dioxide. While equipment conversions are necessary to change from transporting hazardous liquids to the more highly volatile liquids, those changes can be made at the option of the pipeline operator without approval of the regulatory agency. Such a change can drastically increase the risks to public safety.

Unlike its regulations applicable to the natural gas transmission pipelines, the OPS regulations makes almost no difference in its safety requirements concerning the design, construction, testing, maintenance, and operation of liquid pipelines that traverse uninhabited property as compared to pipelines located in densely populated urban properties or in environmentally sensitive areas. Also, the OPS regulations do not require that existing pipelines meet the same safety standards in effect when a new pipeline is constructed. These deficient conditions were discussed in a NTSB report[6] in which the NTSB noted that the OPS had failed to act to require that existing pipelines meet the same minimum safety standards as new pipelines and that the OPS had failed to establish minimum performance standards for the prompt detection and rapid isolation of failed segments of pipelines.

<u>Pipeline Routing</u>**.** - The National Research Council Special Report 219 points out that liquid pipelines are exempt from Federal routing and environmental assessment requirements and these aspects are subject to the individual state requirements. OPS regulations (49CFR195.210) generally address the location of pipelines only by requiring that the "pipeline right-of-way be selected to avoid, as far as practicable, areas containing private dwellings, industrial buildings, and places of public assembly" and that "No pipeline may be located within 50 feet of any private dwelling, or any industrial building or place of public assembly in which persons work, congregate, or assemble, unless it is provided with at least 12 inches of cover in addition to that prescribed in 49 CFR 195.248." In accepting the industry liquid pipeline code, the OPS did so

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[5] Special Study, "A Systematic Approach to Pipeline Safety," (NTSB/PSS-72/1) National Transportation Safety Board, Washington, D.C. 20594. May 25, 1972,

[6] "Safety Report on the Progress of Improvements in Pipeline Transportation of Highly Volatile Liquids," (NTSB/SR-79/03) National Transportation Safety Board, Washington, D.C. 20594, September 28, 1979.

without performing an assessment of the risks posed to people, property, and the environment in proximity of the pipeline with respect to the material transported by the liquid pipeline. [4]

Rights-of-way width. - The OPS regulations do not address the minimum safe width for pipeline rights-of-way. Thus, pipeline operators have no requirement to obtain a right-of-way width adequate for the operator to perform future repairs or modifications to the pipeline or to provide reasonable safety to adjacent people and property. A right-of-way width of about 50 feet is generally necessary for a pipeline operator to operate excavation equipment, to stockpile excavated soils, and to place construction materials whenever a substantial repair or modification must be made to a pipeline. (Pipeline operators generally obtain easements ranging from 50 to 100 feet with a 50 foot width being most typical.[7])

Safety buffer to protect adjacent people and buildings. - The OPS has acknowledged that its hazardous liquid pipeline regulations contain no siting standards[8] and they make no requirement on liquid pipeline operators for providing safety buffers to protect public safety or the environment in the event of releases from pipelines based on the petroleum product transported. In its latest study on casualties and damages due to liquid pipeline incidents, the American Petroleum Institute[9] included information from liquid pipeline operators on the casualties and damages resulting from petroleum releases. The consequences were viewed based on how far the pipeline was from the damage/casualty. The report summarized information on accidents that had resulted in 72 deaths, 184 injuries, and $358 million in property damages. The API report stated, "The available information indicates that 63% and 74% of the reported deaths and injuries, respectively, were within 150 feet of the pipeline while "76% of the deaths, 93% of the injuries, and 87% of the property damage occurred within 220 yards, or 1/8 mile of the pipeline. Five percent of the property damage occurred beyond one-half mile from the line. This information strongly suggests that the distribution of damage, and therefore the likely risk, decreases strongly with distance from the pipeline. Approximately two thirds of damage was within 150 feet and virtually all was within ½ mile."

Leak detection and rapid shut down of failed pipe segments. - Liquid pipeline accidents have emphasized that while they have not historically resulted in large numbers of human casualties nationwide, they have resulted in dollar losses, environmental damages, and disruptions to adjacent communities disproportionate to pipelines that transport natural gases. These losses have not been equitably considered by the OPS in its safety standards, especially in standards on detecting abnormal pipeline operations and on the need for promptly detecting system leaks to minimize the quantity of products released due to leaks and ruptures. Leak events as opposed to full-open pipe ruptures are the most frequent occurrences and can result in significant damage to wetlands, soils, water tables, and surface waters adjacent to a pipeline.

The OPS regulations for constructing, operating, and maintaining liquid pipelines (49CFR195) require that operators have procedures on monitoring pipeline operations and on shutting down pipelines in emergencies to minimize the volume of hazardous liquids released in the event of a failure. However, those requirements do not include any criteria or guidance on establishing what are acceptable detection standards regarding the sensitivity of an installed detection

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7 Special Report 219, "Pipelines and Public Safety," Transportation Research Board, National Research Council, 1988, pp. 65-67

8 Pipeline Accident Report, " Texas Eastern Transmission Corporation Natural Gas Pipeline Explosion and Fire, Edison, New Jersey, March 23, 1994," National transportation Safety Board, Washington, D.C. 20594 (NTSB/PAR-95/01) p. 67.

9 "The Safety of Interstate Liquid Pipelines; An Evaluation of Present Levels and Proposals for Change," Research Study #040, American Petroleum Institute, 1220 L. Street, Northwest, Washington, D.C. 20005, July 1987.

system, timeliness of detection after an event, timeliness of action to isolate a failed pipe segment after a release is detected, or the maximum volume of product allowable between isolation valves. Consequently, a pipeline operator is free to select any monitoring system, valve spacing, and type of valve operator that meets operational needs without having to give consideration to public safety or environmental needs.

The regulations require the installation of shut-off valves (manual valves comply) at pump stations, storage facilities, lateral takeoffs, on each side of reservoirs holding water for human consumption, on each side of water crossings more than 100 feet in width, and at other locations determined by the operator that will minimize damage or pollution from accidental hazardous liquid discharge. The valve locations and spacing along the line are to be selected by the operator with consideration of the terrain and area population. There is no requirement for the operator to consider future development, even if plans are in place, nor is the operator required to add valves when the area adjacent to the pipeline becomes developed. Furthermore, there is no requirement that the operator equip pipeline valves with automatic- or remote-controlled actuators so that a ruptured or leaking pipeline segment can be promptly isolated to minimize damage to surroundings.

Operators normally use manual valves which requires a person to be at the valve site to close the valve. The closure of such valves usually involves delays of an hour. Due to the distance the employee must travel and traffic congestion, delays maybe up to 4 or more hours. Operators use remote- and automatic-operating valves at pump stations and delivery points so they can be control from a central dispatch location. Valves generally are not spaced along the pipeline to minimize the quantity of product released after a failure based on the risk posed by the liquid product in the pipeline. Valves and the type of valve operator are generally selected by pipeline operators based on operating control needs rather than public safety or environmental needs.

Periodic Pressure Testing and Internal Inspection. - After initial construction and testing of liquid pipelines, the Federal regulations make no requirement for periodic pressure or other tests to confirm the adequacy of the pipeline to remain in service or to continue operation at the maximum initial operating pressure. Also, pipeline operators are not required to perform internal inspections of pipelines to identify potentially harmful conditions, such as pipe wall metal loss due to corrosion or pipe damage from mechanized equipment, that may result in failure with continued operation. Periodic reassessment of the condition of a pipeline is important because these facilities, based on the ages of existing pipelines, tend to remain in service 50 or more years. Also, the pipeline is located through environments not under the operator's full control and where mechanical damage to the pipe can result, where corrosion of the pipe wall can occur even though a corrosion control system is operating, and where fatigue of the pipe metal can occur due to frequent, large internal pressure fluctuations. Periodic reaffirmation of the system adequacy for continued safe operation is essential to minimize future releases of product.

PIPELINE RELEASES FROM LIQUID PIPELINES AND CONSEQUENCES

The previous 20 years of available data reported by pipeline operators to the OPS indicate that about 172 million gallons of oil and petroleum products were released from pipelines in the United States with those releases resulting in reported property damage losses of about $433,378,000. (See Table 1.) While impressive, those figures do not truly reflect the total losses caused by liquid pipelines due to leaks and ruptures: the reports filed by pipeline companies are not audited by the OPS and many types of losses are not required to be reported. Additionally, all costs associated with pipeline incidents are not required to be reported, costs such as those borne by communities in responding to releases, polluted soil no longer useable, the value of fish and wildlife kills, damages to ecological organisms and structures, court costs, out-of-court monetary settlements, and monetary awards by juries.

To illustrate the inadequacy of the data provided to the OPS through its liquid pipeline incident reporting, the damage claim of one South Carolina property owner affected by a 1996 liquid pipeline release was recently settled out-of-court for $8.5 million whereas the pipeline operator reported the property damage loss as being $100,000. The underreporting of damage costs is a major problem confronting the OPS when attempting to show the benefit of strengthening the liquid pipeline requirements, yet the OPS has not modified its reporting requirements to include usual and reasonable costs that result when liquid pipelines release product into the environment.

Even based on the incomplete data in Table 1 for the 20 year period, the average quantity of liquid products released per event was about 42,000 gallons with an average of 206 releases per year. There are no liquid pipelines in some states, even so on average, this would equal four major liquid product releases for each of the 50 states each year. (See Appendix A for examples of hazardous liquid pipeline release accidents.)

Table 1: Consequences of Spills and Leaks from Oil and Petroleum Product Pipelines in the United States, 1978-1997, as Reported by Pipeline Operators to the Office of Pipeline Safety: Source - OPS Statistics

Year	# Accidents	# Injuries	# Fatalities	$ Property Damage	# Gallons Spilled
1978	254	10	3	6,093,361	11,779,530
1979	250	13	4	120,152,266	22,900,248
1980	218	15	3	5,419,463	12,005,238
1981	236	32	5	5,226,657	8,588,622
1982	196	6	1	1,478,530	9,214,926
1983	159	9	6	7,028,934	16,020,942
1984	186	17	0	2,065,016	7,248,620
1985	183	18	5	5,132,647	6,277,320
1986	209	32	4	16,027,846	9,215,346
1987	237	20	3	13,140,434	13,131,468
1988	193	19	2	32,414,912	4,798,542
1989	163	38	3	8,813,604	5,089,518
1990	180	7	3	15,720,422	2,295,846
1991	216	9	0	37,788,944	2,342,508
1992	212	38	5	38,651,062	2,887,164
1993	230	10	0	28,873,651	2,440,536
1994	244	1,858	1	56,453,604	4,718,700
1995	188	11	3	32,518,689	22,307,746
1996	195	13	5	49,704,731	4,037,922
1997	179	0	0	38,896,602	4,699,674
Total	**4,128**	**2,175**	**47**	**433,377,955**	**172,000,416**
Avg. Annual	**206.4**	**108.75**	**2.35**	**21,668,897.75**	**8,600,020.8**

As shown in the Application (page 2.9-4), between 1979 and 1997, Olympic Pipeline Company contributed about 544 thousand gallons of the more than 172 million gallons of hazardous materials product reported to the OPS as being released from pipelines in the United States. But Olympic did not disclose all releases it has experienced. Table 2 shows information from 5 incident reports OPL reported to the OPS during that time period but did not include in its application. The reported property damage for a 11/28/85 release was $1 million, a 5/8/86 release was $220,000, a 8/30/88 release was $162,000, a 1/17/91 release was $300,000. The 1/17/91 release also resulted in a fire and explosion. The quantity of released product due to these 5 additional releases was about 250,000 gallons. This would increase the product release volume reported by OPL in its application by about 50 percent.

Table 2: Product Releases by Olympic Not Disclosed in the Application **Source: OPS Incident Reports**

Date	Location	Cause	Product	Loss BBLs
11/28/85	Sea-Tac	Operating error	Jet Fuel	745
5/8/86	Tukwila, WA	Failed pipe	Diesel	1974
9/25/86	Renton, WA	Thread crack	Gasoline	0 BBLs
8/30/88	Skagit, WA	Failed pipe	Diesel	3250
1/17/91	Spanaway, WA	Elec. Mtr/Pump	Diesel	2BBLs

LIQUID PIPELINE INSPECTION AND ENFORCEMENT

The OPS has been long criticized by the U.S. Congress[10], the U.S. General Accounting Office[11], and the Safety Board[12] for its lack of effective monitoring and enforcement of the pipeline safety regulations. Most recently, the Safety Board criticized the OPS for failing to effectively monitor the operations of the Puerto Rico Public Service Commission and of the San Juan Gas Company[13]. The Safety Board concluded that the OPS failure to effective monitor compliance contributed to the occurrence of the explosion. In part, the reason for OPS's failure to effectively monitor its safety requirements is its lack of sufficient personnel to perform inspections. Another reason is due to OPS's philosophy of not penalizing violators once deficiencies are identified. The OPS's long-held view is that to penalize an operator takes money from operators that could be better used for correcting deficient conditions. This philosophy supports an industry view of "don't fix until OPS finds" and thus discourages some within the industry from performing their own progressive compliance audits to identify and remedy safety problems in advance of OPS inspections.

THE APPLICATION

Project Summary

Pipelines rated Safest (Page S-7) - The applicant has not documented the validity of this statement for the environment within which it plans to operate. While highway and rail transport of hazardous materials are generally considered less safe that pipelines in terms of injuries and fatalities, marine barge transport is considered as safe as pipelines. Also, future marine transportation should produce fewer releases of product to the environment because they are required to be retrofitted or replaced with double-bottom hulls. The applicant did not assessed the spill reduction consequences for barges when this program is complete nor did it take into account the fact that currently 65 percent of petroleum product shipments on the Columbia River are in double-hulled barges. Furthermore, the applicant did not address the potential spill reduction consequences of employing double-wall pipe construction for the

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10 "Pipeline Safety," Hearing before the Subcommittee on Surface Transportation of the Committee on Public Works and transportation, House of Representatives, One Hundred Second Congress, First Session, September 25, 1991.

11 "Pipeline Safety—Need for a Stronger Federal Effort, U.S. General Accounting Office, April 26, 1978.

12 NTSB/PAR-82/03; NTSB/PAR-87/02; NTSB/PAR-88/01; NTSB/PAR-90/01; NTSB/SIR-96/02; NTSB/SIT-96/04.

13 Pipeline Accident report, "San Juan Gas Company, Inc/Enron Corp. Propane Gas Explosion in San Juan, Puerto Rico, on November 21, 1996," National Transportation Safety Board, Washington, D.C. 20594 (NTSB/PAR-97/01) p. 59.

pipeline or for pipeline segments in environmentally sensitive areas. Secondary containment capabilities for pipeline facilities, while not required by regulation, are technically possible.

The data as reported to the OPS since reporting began in 1970 show that an average of 225 liquid pipeline accidents occur each year with those accidents having resulted in an annual average of 4 fatalities, 81 injuries, $25 million in property damages[14], and release of 10,743,888 gallons of products. To be comparable with the loss of product from pipelines over this same time period, there would have had to have been annual total container releases of petroleum products from about 1,343 tank trucks or from 430 rail tank cars. Pipeline transportation, while perhaps more economical than transport by highway and rail vehicles, has not been shown to be safer as it relates to the release of products into the environment.

OPL Spill Response and Prevention (Page S-6) - The applicant advises that "A primary means by which a pipeline's impact on the environment can be minimized is through comprehensive spill prevention and response efforts." While needed, such means are reactive. A proactive and more positive approach to the prevention of environmental from spills would be through improved system design, control, and monitoring. (See comments on Section 2)

State-of-the-Art Spill Detection Technology (Page S-6) - The SCADA system planned to be used, while gathering data more frequently that most pipeline systems to perform operational checks and having a leak detection subsystem, does not constitute a state-of-the-art spill detection system. Also, the applicant does not indicate that any ergonomic design or other human performance consideration has been given to the control room layout, its lightning, system screen displays, keyboard inputs, or controller reaction to system visual and audible alarms. While the controller may be able to "shut down the entire pipeline or parts of it at any time," controller training better prepares them for continued operation of the pipeline rather than recognition of events requiring immediate shut down. (See comments to Section 2.)

Review of the information provided on the pipeline leak detection subsystem proposed to be used for OPL's monitoring of the Cross Cascade Pipeline Project includes no information on leak detection sensitivity, timeliness of leak detection, accuracy for identifying leak location, or reliability of leak detection capabilities. The information on the proposed leak detection system advises, in part, that:

- Certain types of instrumentation are required for leak detection, while additional instrumentation will improve results. Additional pressure, temperature, and flow sensors greatly improve performance.
- The system is based on real time simulation of flow in the pipeline with a rigorous transient computer model driven by SCADA. The leak detection subsystem detects leaks by comparing the change in the line pack (mass) calculated by the real time model with the net flow balance.
- The leak detection subsystem has multiple averaging periods to quickly detect large leaks while still looking for smaller leaks over a longer time. This guards against false alarms by averaging out noise over a longer time interval, and achieves the goal of minimizing the total fluid lost from a leak.
- The subsystem provides leak size estimates arising directly from the volume balances.
- The subsystem provides leak location based on relative end point volume deviations.

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14 OPS data for the years 1970 - 1977, 1987, and 1988 did not include property damage reports, thus the average is based on the total for the years with reporting divided by the number of years that contained data.

- The subsystem model is automatically tuned so that the calculated quantities agree with the measured quantities. An incorrect model, or a model tuned to bad data, will develop errors in response to flow changes. During a leak the concept of model tuning is not valid. Tuning is disabled while a leak alarm is active, and re-enabled when the alarm is cleared.
- Leak analysis is done by volume balance sections, which are user-defined sections of the pipeline.
- The alarm threshold adjustment functions can be edit by the user.
- Performance of a leak detection system is defined in terms of its sensitivity, response time, and false alarm rate.
- The sensitivity is the smallest detectable leak. Actually, the sensitivity is coupled to the response time, since large leaks produce large effects which are quickly detected, and to the false alarm rate, since decreasing alarm thresholds increase both the sensitivity and the false alarm rate. The ultimate leak detection sensitivity, rarely achieved in practice, is the minimum repeatability of flow measurements surrounding the section.
- The response time for a given sensitivity and false alarm rate depends on the SCADA scan interval and the distance between measurement points on the pipeline. Clearly no leak can be detected until its effects have propagated to the nearest measurement point, and the next SCADA scan has picked up the effect. The actual response time is always longer that this physical minimum (usually much longer), because the effect at the measurement point must grow until it causes a change in the measured quantity greater than the measurement sensitivity, and several SCADA scans must be used to reduce the noise and eliminate "spikes" in the data.
- The false alarm rate depends on the noise in the volume balance, which is the aggregate result of all the errors and limitation of the sensors, the telemetry encoding, and the SCADA scan interval.
- Most of the pipeline leak detection system code is devoted to reducing false alarms.
- Ultimately, the false alarm rate is selected by the user of the pipeline leak detection system by setting alarm thresholds to provide the (subjectively) optimum trade-off between the sensitivity, response time, and false alarm rate.

With all of the above stated, the Modisette Associate, Inc., designer and installer of the leak detection subsystem, makes no claim as to the sensitivity, response time, or repeatability of the leak detection system. Most importantly, the information reveals that all of these factors are up to the pipeline operator and that after being installed, the pipeline operator can adjust the system to meet its operating requirements to the detriment of the leak detection capabilities.

State-of-the-art leak detection systems employ detection techniques that address the following areas:

- Detection of leak occurrence
- Prediction of leak location
- Prediction of leak size

Techniques currently available which address one or more of these aspects include:

- Volume/Mass balance
- Pressure point monitoring
- Real time modeling
- Statistical analysis

- Hydrocarbon reactive cable
- Acoustic monitoring
- Double-wall pipe construction with monitoring of the annulus (space between pipes)

Hydrocarbon reactive cable systems are generally site specific systems used to monitor short sections up to several miles of pipeline located in sensitive areas. The cable is buried adjacent to and slightly below the pipe level. The cable outer covering is impervious to water but will pass hydrocarbon vapors. Continuous monitoring of the cable is performed by pulling air through the cable into a hydrocarbon detector. Systems are available to detect hydrocarbon levels as low as 0.2 percent hydrocarbon vapor in air and are able to identify the source of the hydrocarbon within about 5 feet. The Williams Pipe Line Company is now using this type leak detection system for the several miles its hazardous liquid pipeline that crosses a aquifer (natural underground lake) near Sioux Falls, South Dakota.

Clamp-on meter leak detection systems are full-functioned pipeline leak detection systems suitable for interstate petroleum pipelines. They are capable of being one of the fastest available detector systems for small or catastrophic leaks. These systems consist of a master station that polls the clamp-on line meters periodically and then performs volume balance computations based on multiple integration periods from one to sixty minutes. A clamp-on meter leak detection is now being used by Cal-Nev for its hazardous liquid pipeline that cross the mountain ranges between San Bernardino, CA, and Las Vegas, NV.

Pressure point and mass volume balancing leak detection systems can detect within seconds flow from holes as small as 1/16 inch and losses as low as 0.1 percent of pipeline flow. This type system has been required by the State Fire Marshal for years for that portion of the Buckeye Pipe Line in the State of New York. Early experience with the system resulted in numerous false alarms requiring unnecessary shut down of the pipeline; however, after working with and modifying the system, it now performs well to identify leaks and their locations along the pipeline. This type leak detection system is also used by several other U.S. onshore pipeline operators including ARCO and by offshore and foreign pipeline operators. One such leak detection system manufacturer, EFA Technologies, Inc., (FFA) reported in its August 1997 *Current Events and Excitement* newsletter that its leak detection system had undergone third party testing in accordance with U.S. Environmental Protection Agency (EPA) approved protocol. The testing involved 60 leak tests designed to establish its system's ability to reliably detect the EPA target leak of three gallons per hour and smaller. The tests were conducted on an 18-inch diameter pipeline containing 58,000 gallons operating at line pressures ranging from 60 to 120 pounds per square inch gauge. The losses at detection were usually 1/10 of a gallon. To receive certification, the detection system had to perform correctly in at least 95 percent of the tests. The EFA reported that its system correctly processed the 60 tests for a perfect 100 percent record.

Real time monitoring of pipeline systems using acoustic leak detection systems can provide prompt detection of leaks and ruptures, usually within one minute, and identify the location of the release within about 500 feet. When a hole in the pipeline forms, fluid escapes in the form of a high-pressure jet. Fluid loss produces a sudden pressure loss in the pipeline which propagates in both directions as acoustical signals. Acoustical signals propagate with the speed of sound in the fluid and over long distances in the pipeline due the low signal absorption and because the pipe wall guide the wave fronts.

The designers of the proposed Yellowstone Pipe Line state that its pipeline control system is capable of detecting "leak rates larger than 20 BBLs (840 gallons) per hour (14 gallons per minute) within a 7.5 minute time window." In addition, pressure and temperature along the pipeline is transmitted through the SCADA system to enable operators to recognize any deviation from normal. Also, the local control systems at each pump station are to be programmed to execute a systematic shut down of the pipeline in the event of a communication loss from the master station after a predetermined elapse of time.

The designers of the Yellowstone Pipe Line, apparently acknowledging the inability of the SCADA and leak detection systems to detect small, but environmentally important leaks, plan to conduct shut-in leak tests about every ten (10) days to supplement its on-line dynamic leak detection system. The test will consist of verifying the calibration of pressure and temperature devices on the pipeline and, through a shut-in leak test algorithm, automatically perform a shut-in test each time when flow through the pipeline is shut-down and remote block valves closed. The minimum test duration will be four hours and during that period the algorithm will continuously monitor the pressure and temperature variations to identify if such pressure changes indicate leaks. The shut-in test results are to be verified by a qualified engineer before the pipeline may be restarted. It is estimated that the shut-in leak test will be capable of detecting a fixed 5 BBL release over a time range of 7.5 minutes to 24 hours.

Double-wall pipe construction has been used in above ground plant systems for years as a means of preventing the release of hazardous materials to the environment and to monitor for leaks. At least since the 1970's, double-wall pipe has been used in sensitive environments by other countries and in recent years has been used for some segments of U.S. in pipelines as a means to prevent the release of product in sensitive areas and to monitor for leaks. As reported in an August 3, 1998, letter from the U.S. Department of Interior to the Alaska District Engineer for the U.S. Army Corps of Engineers, "ARCO Alaska, Inc. is using a double pipeline design (sales oil pipeline inside a high-strength casing pipe) with a leak detection system (pressure sensors, vapor detectors or hydrocarbon liquid detectors) installed between the two pipelines (Parametrix Inc. 1997:2-28 - 2.30). The Service suggests that there is no more appropriate location to utilize the most advanced leak detection system available than under the Beaufort Sea." The September 1997 Alpine Development Project Environmental Evaluation Document, page 2-28, describes this project's intended use of double-wall pipe as follows:

> To further prevent a pipeline leak under the Colville River, the sales oil pipeline will be installed inside a high-strength casing pipe. This "pipeline-within-a-pipeline" approach is fairly unique for HDD [horizontal directional drilling] pipeline river crossings. Simultaneous failure of both the sales oil pipeline and the casing pipe is highly unlikely. If oil leaked from the sales oil pipeline, it would be captured within the space between the outer wall of the sales oil pipeline and the inner wall of the high-strength casing pipe, rather than reaching the subsurface river environment. This design is analogous to secondary containment provided as a spill prevention techniques for storage tanks….The casing performs a second function in that it is designed to accommodate the external loads that would normally be carried by the carrier pipe….To prevent external corrosion, all of the casing pipes and carrier pipes are protected by a mechanically tough state-of-the-art fusion-bonded epoxy coating. In addition, and in response to comments regarding additional prevention, another 8-inch

pipe parallel to and near all of the casing pipes provides the anode portion of a cathodic protection system to prevent corrosion of the casing pipes.

The encasement of short segments of pipelines beneath road, railroad, and stream crossings has long been recognized in the pipeline industry codes (B-31.4 [liquids] and B-31.8 [gas]) and the Federal regulations (49CFR192 & 49CFR195) as a means to minimize the adverse affects of excessive external loading on pipelines and to minimize the affects of mechanical damage. The major differences between these encasements and double-wall pipe segments is that the encasements were never intended to contain the pressure of the product being transported through the pipeline in the event of a carrier pipe failure and the encased segments generally were only a few hundred feet in length. Current technology has obviously extended the potential uses of encased pipe to pressure containment and leak detection. There are more than 270 miles of double-wall pipe currently in pipeline service.

State-of-the-Art Cathodic Protection (Page S-6) - Corrosion protection (cathodic or anodic) for pipelines is essential for mitigating external corrosion and reducing the potential for leaks and structural failure of the pipeline and buried appurtenances. However it is important to understand that corrosion control measures are mitigating rather than preventive actions. Even with the best of corrosion control systems, corrosion can and does occur on the pipe due to there being areas along the pipeline where the protective system is shielded from the pipeline due to rock outcroppings, coating damage, and other factors. Further, it should be recognized that neither the Federal regulations (49CFR195) nor this application include any standard or criteria to which a corrosion protection system is to be constructed and monitored. Without specificity by the applicant as to the design and use of this system, there are no protection levels or other performance criteria against which to assess the adequacy of the system proposed to be installed.

The applicant addresses its intention to use a “smart pig” (internal inspection device) to detect corrosion, dents, or other defects in the pipe wall so that repairs can be made before a leak can develop. The use of such devices are not required by regulation and if used, this inspection would exceed the Federal requirements. However, for one to assess the value of the device(s) to be used, the applicant must first specify which device or combination of devices are to be used. This is needed because some devices will not identify certain pipe defects such as cracks in the pipe wall while others may not identify gouges in the pipe wall if the gouge is elliptical with the larger ellipse axis aligned parallel to the pipe axis. Later, in Section 2, the applicant states the frequency of use intended, but the specific device or devices are not identified. Internal inspection equipment is available for performing a large variety of inspection/testing tasks and the term itself does not define a specific instrument. One could employ only a caliper device to measure out-of-roundness and locate dents. A magnetic flux tool could be used to identify pipe wall reductions and dents and this tool can be either a low or high resolution tool. One could also use the more sophisticated tools available from Great Britain, Germany, or Japan which can identify pipe wall reductions as well as cracks in the pipe metal. Without a declaration as the capabilities of the internal inspection device to be used, there is no way to assess what, if any, safety improvement will be achieved. Furthermore, an internal inspection of the pipeline should be conducted before the pipeline is placed into transportation service to provide a baseline documentation of the pipe against which future inspections are to be compared. This is not addressed in the application.

Modern Pipeline Construction Techniques (Page S-6) - The applicant professes that the pipeline will be constructed using the most modern pipe and construction techniques. Then the applicant advises that this pipeline will be superior because acetylene welding will not be used. This technique for joining high-pressure pipelines has not been in use for more than 40 years and certainly no knowledgeable pipeline operator would consider its use today.

The applicant also advises that it will use high-grade steel that is high in "ductility," but the pipe standard stated is for normal line pipe. If the applicant intends to use pipe that has toughness properties (properties needed for higher steel ductility so the pipe can bridge certain defects without failure) as an added measure for minimizing the potential for the pipe to rupture due to corrosion or external force damage, it must specify in its pipe order the desired pipe toughness properties in addition to the API line pipe designation. For example, it could specify the toughness properties in the API standard appendix which will not apply unless designated by the purchaser.

Confining Pipeline to Existing Corridors Minimizes Impact on Wildlife and Plants (Page S-10) - The proposed 30-foot wide right-of-way after construction of the pipeline will not provide adequate width for the applicant to maintain, repair, or modify as necessary the pipeline. Incursions into the right-of-way after construction will of necessity result in future damage to adjacent and possibly environmentally-sensitive lands. A greater right-of-way width is needed to stockpile pipe and materials, provided space to operate equipment, several sidebooms and/or backhoes, and provide space to work on the pipeline.

Section 2 Proposal
.1 **Summary of Existing System (Page 2.3-2)** - No standard is specified for the installation of the impressed-current cathodic protection system for the pipeline.
.2
2.3.2.3 **Pipe Wall Thickness Design (Page 2.3-3)** - Using the pipe specifications cited, the 14-inch pipe should withstand without rupture 2,087 pounds per square inch (psi) internal pressure and the 12-inch pipe should withstand 2,167 psi. The Federal regulations will permit the 14-inch pipe to operate at 1,503 psi and the 12-inch pipe to operate at 1,560 psi. The applicant specified that the maximum system pressure will be 1440 psi. which will comply with the regulations for usual buried pipe installations. Bridge, rail, and river crossings may require increased wall thickness (increased strength steel could also be used) to withstand other pipe loading such as impact, suspended weight, and vibration. Those final designs should later be submitted for review and approval by the regulatory body.
2.3.2.4
2.3.2.5 .3.2.**Pipe Yield Strength (Page 2.3-3)** - The Applicant identifies the pipe specification as API Specification 5L, but does not identify what, if any, pipe toughness criteria is to be achieved. This is where the applicant must identify how it is to achieve the promised increased "ductility" cited on Page S-6. Increased toughness for pipelines is a highly desirable quality since the pipe material notch toughness properties can be improved to make the pipe steel less susceptible to brittle fracture during cold periods and to make the pipe steel more capable of bridging without failure small and moderate size corrosion pitting or metal gouge defects. The advantages of improving pipe metal toughness was addressed by the NTSB in a 1995 report.[1] The NTSB stated that it "is concerned that neither current industry codes nor Federal

[1] Pipeline Accident Report, Texas Eastern Transmission Corporation Natural Gas Pipeline Explosion and Fire, Edison, New Jersey, March 23, 1994 (NTSB/PAR-95/01), pp 66-64.

regulations contain minimum standards for pipe toughness properties. The current API specifications for line pipe [API5L, November 1, 1992] includes fracture toughness testing standards. However, the section is only a supplemental reference that operators may use when ordering pipe….Increased toughness properties can protect the public by preventing pipe failures of by minimizing the consequences of failure. Should a pipe having increased toughness properties fail, the opening in the pipe will be smaller, which results in gas [product] being released at a lesser rate within a given time." The NTSB recommended to the OPS that it "Develop toughness standards for new pipe in gas and hazardous liquid pipelines, especially in urban areas. (P-95-2)" The OPS has not acted to implement this recommendation.

The applicant also attempts to induce the reader of the application to believe that the pipe to be used will be better that the norm by implying that all pipe will be enhanced because the manufacturer will provide a greater minimum yield strength for all pipe segments than that which is specified. Generally manufacturers use a slightly higher yield strength steel than specified, but the intent is to give the manufacturer confidence that even the weakest segment of pipe will equal the minimum required yield strength. What, if any, increased yield strength that may result should not raise confidence that the pipe is stronger than required; rather it should give confidence that every pipe segment is at least as strong as required. No increased safety factor should be attributed to the pipe.

2.3.3.1 Land Pipeline Construction

Pipe Stringing (Page 2.3-10) - The applicant does not identify the pipe coating standard, whether the line pipe coating will be electrically tested to assure adequate electrical isolation, and if the pipe coating will be repaired and retested as needed. Since weld joint coating are to be electrically tested, one might presume that the pipe coating will also be tested; however, this should be stated rather than presumed.

Joint Coating (Page 2.3-12) - The applicant identifies the coating and process it will use for weld joints and advises that it will conduct electric testing to determine if the coating has any nicks or abrasions. Not specified is the standard it will use to electrically test the coating and what action will be taken should a nick or abrasion be found. Actually, the test is not conducted to identify nicks and abrasions, rather it is tested to determine that the coating in place has sufficient electrical isolation properties. This is done to improve the performance of the corrosion protection and to lower the cost to provide the protection.

Cathodic Protection (Page 2.3-12) - The applicant has not stated the corrosion protection standard that will be met in designing the system and the Federal regulations do not specify a standards for liquid pipelines. Thus, there is no assurance as to the level of corrosion mitigation that will be provided. Also, the applicant is under the misguided apprehension that these systems prevent corrosion. These systems only mitigate, as opposed to prevent, corrosion risks because some forms of corrosion protection have little or no effect on bacterial and other types of corrosion.

The drawings for the corrosion control system provided in this section are not informative since the applicant has not adopted a recognized corrosion control standard to which the facilities will be designed and constructed.

Pipe Cleaning and Hydrostatic Testing (Page 2.3-22) - The applicant advises that the entire pipeline will be tested in accordance with DOT regulations. Paragraph 195.303 requires that the pipeline be tested for at least four continuous hours at a pressure equal to 125 percent of the maximum operating pressure. If the pipeline is not visually inspected for leakage during this test, then the pipeline must be tested an additional four continuous hours at a pressure equal to 110 percent, or more, of the maximum operating pressure. This means that the maximum test pressure to which the pipe must be subjected is 1,800 psi, or only 86 percent of the 14-inch pipe design , 83 percent of the 12-inch pipe design pressure, and even less for river, road, and railroad crossings that are to have a wall thickness greater than the standard pipe. This means that the pipe installed will not be strength tested to assure that it can withstand its design pressure rating. Most natural gas transmission pipelines, which use the same pipe design principles and in fact the same pipe, are now being strength-tested to 100 percent of the pipe design to assure that the pipe installed is as advertised and to remove from the pipeline before beginning operation any pipe segments that can not withstand the pipe design pressure.

2.3.4 Valves (Page 2.3-24) - The applicant is not clear in the proposal on whether all line block valves installed as indicated in Table 2.9-2 will be remotely operable. This is inferred by the wording and if this is not correct, the applicant should be required to incorporate remote control actuation for each of these valves. The last sentence in this section refers to the SCADA system being able to detect and alert the pipeline dispatcher of any abnormal occurrences at the valve site. The detection capabilities for these valve sites should be identified.

2.3.5 Pump Stations (Page 2.3-26), 2.3.6 and Terminal Facility (Page 2.3-33) - Other than general statements, the Federal regulations contain no requirements on the design, testing, maintenance, and operation of pump stations and terminal equipment, including storage tank facilities. The applicant provides no information as to the standards it will use in the design of these facilities, including the tank storage facilities, nor specific information as to the types and numbers of controls, and other safety devices. While many storage tanks and facilities must comply with the requirements of the U.S. Environmental Protection Agency, those tanks that are used for temporary storage while in transportation, surge tanks, or breakout tanks are not required to meet those standards. The applicant should be made to comply with the EPA standards throughout since the OPS has no such standards.

2.3.8 Communication System (Page 2.3-40) - Since this system is critical to the monitoring of pipeline operations, the standards to which these facilities are to be designed, constructed, tested, and maintained should be specified.

2.9.1 Regulatory Requirements (Page 2.9-1) - Olympic has an oil spill prevention, control, and contingency plan on file with the OPS for its existing pipeline and likely will prepare the same type of plan for this pipeline. The problem with this is that the OPS does not require pipeline operators to meet the full extent of the Oil Pollution Act of 1990. OPA 90 and 49 CFR 194 require that operators of liquid pipelines develop and submit to OPS (Research and Special Programs Administration [RSPA] the parent organization for OPS) for approval a response plan that defines the operator’s planned resources for responding to a (1) worst-case discharge and (2) substantial threat of such discharge. The OPS in its guidance to the pipeline industry required the submission of a plan to meet only item (1) above. During its investigation of spills from pipelines crossing the San Jacinto River near Houston, Texas, in 1994, the National Transportation Safety Board (NTSB) recognized that pipeline operator spill response plans did not include actions on responding to events that pose substantial threats to pipeline that might result in product discharges and discussed this deficiency with the OPS. In response, the OPS sent to each pipeline operator a letter advising that operators must be prepared to respond to substantial threats to pipelines, but contrary to OPS 90 requirements, the OPS did not require operators to submit for approval their plans. In its 1996 Special Investigation Report,[1] the NTSB reviewed the action the OPS took concerning operator plans for responding to substantial threats and advised the OPS that it must do more. The NTSB advised that "Recognizing potential threats to pipeline failures and developing means to remedy or minimize such threats require actions significantly different from those needed to develop product cleanup processes. Consequently, for RSPA to cause each operator to recognize and be prepared to respond to substantial threats of product discharges, it must require operators to identify events most likely to pose substantial threats to their pipelines. In so doing, each operator should be able to compare the forces that might be imposed on its pipeline, weigh those forces against the design capabilities of its pipeline, and identify locations where the potential for damage is greatest. Based on such evaluation, the operator would be able to develop actions plans to remedy or minimize the identified threats." The NTSB then recommended that RSPA, "Require operators of liquid pipelines to address in their Oil Pollution Act of 1990 spill response plans, identifying and responding to events that can pose a substantial threat of a worse-case product release. (Class II, Priority Action) (P-96-21)."

The above recommended action has not been accomplished by the OPS and there are no plans for it to do so. The pipeline operator should be made to comply with the OPA 90 provisions before consideration is given to authorizing construction of the pipeline. In so doing, the operator would have to identify potential release scenarios that could result in the most harm to people and the environment given the pipeline as proposed, including its leak detection capability, its ability to rapidly isolate a failed pipe segment (not just shut down the pumps), and prevent continuing product release into sensitive areas. Such analysis should point up areas in which the proposed system will not be adequate to timely detect product leaks/releases and identify portions of the pipeline where specialized leak detection systems, such as hydrocarbon leak detection cable and alerting systems, need to be installed to promptly alert of release volumes below the capability of the SCADA system.

2.9.2 Potential Risks for Liquid Pipeline Releases (Page 2.9-2) - The California State Fire Marshal's 1993 report related only to pipelines in the State of California most all of which traverse non mountainous urban environments. Even though that study is not directly applicable to the pipeline in question, the percentages given for the various causes of product releases are reasonably in line with national statistics produced by the OPS.

On many pipeline segments, manual valves are spaced 20 or more miles apart; thus a spill quantity equal to 75% of the volume between block valves can be huge. Also when a pipeline is located in undulating but not mountainous terrain and manual valves are employed, the volume of product released after the pumps are shut off is influenced more by the variations in pipe elevations rather than valve spacing. Therefore when a pipeline operator is slow to respond to a spill site to close the manual valves on each side of the release, the size of the release is not influenced by the closing of adjacent valves. However, in situations where remote- or automatic-operated valves are employed, an objective look at the spill statistics would have found that the quantity of product released could have been substantially less if the

[1] Pipeline Special Investigation Report, Evaluation of Pipeline Failures During Flooding and Spill Response Actions, San Jacinto River Near Houston, Texas, October 1994, (NTSB/SIR-96/04).

operator had promptly learned of the release through an effective leak detection subsystem and then immediately shut the system down and remotely or automatically closed valves on each side of the release point.

The California State Fire Marshal study findings that there was little statistical correlation between the spill size and block valves spacing and that 50 % of the spill volume represented only 75% of the volume between adjacent block valves is not surprising. To better understand the above findings, one needs to understand several factors about liquid pipeline operations. Few liquid pipelines are equipped with remote- or automatic-control valves in pipeline segments between pump stations. Also, control center operators receive extensive training on how to keep the pipeline transporting product and compared to the operating training, they receive little training on recognizing leaks or ruptures and the importance of promptly shutting down the pipeline. Unless the operating information received in the control center makes it clear that only a pipe rupture could be the reason that an abnormal operating alarm was received, like the applicant's statement, a pipeline operator's first action is to search for an operational problem to explain the alarm. Only after not being able to justify the cause of the alarm as being an operational problem will an operator begin to consider if the cause might be indicative of a product release. While a pipeline operator might shut down pumps, often other action will not be taken until on site leak verification has been made. After that, the pipeline will be shut down and personnel will be dispatched to close manual valves on either side of the confirmed release point.

The pipeline operator's focus on keeping the pipeline system operating and the lack of remotely-operable valves are the primary factors that control the quantity of product released after a rupture or leak. Even with remote control valves this relationship will not change unless the pipeline is equipped with a reliable leak detection subsystem that works with the SCADA system and those who control pipeline operations are trained for and dedicated to minimizing product release (safety and environmental mindset) rather trained for and dedicated to keeping the system operating (economic mindset). To illustrate the reluctance pipeline controllers have for shutting down a pipeline (economic mindset), a liquid pipeline controller being questioned after a major product release[2] testified that when the abnormal operating condition occurred, his first thought was that a pump station was out without his knowledge. Although he acknowledged that he had unrestricted authority to shut the pipeline down, he stated that shutting down the pipeline is a judgment call and he opted instead to call the pump station operator to discussed what event may have occurred. When asked if the pipeline ever gets shut down periodically by controllers, he responded that it occurs "Every now and then but it's -- you know, you usually tell the shift supervisor and, you know, you wait -- I'd say 90 percent of the time you wait -- you know, you tell the shift supervisor and then they'll determine whether to shut it down or not." When asked if there was a personal penalty for shutting the pipeline down on his own accord, he advised that he didn't know and added that if you just kept shutting the pipeline down he was sure that management would frown on you.

An important finding in a 1995 RSPA study[3] (which reviewed the California State Fire Marshal's report) and not noted by the applicant was that "The average spill size on OPS-

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[2] National Transportation Safety Board Deposition, March 18, 1997, Concerning PIPELINE ACCIDENT, THAT OCCURRED at the REEDY RIVER IN FORK SHOALS, SOUTH CAROLINA, JUNE 26, 1996 and MURFREESBORO,TENNESSEE ACCIDENT THAT OCCURRED ON NOVEMBER 5, 1996, Accident No. DCA96MPOO5 and DCA97FP002

[3] *Remote Control Spill Reduction Technology: A Survey and Analysis of Applications for Liquid Pipeline Systems*, Volpe National Transportation Systems Center, September 29, 1995.

regulated pipelines is frequently less than the potential volume of product in a segment of average length, but there may be benefits to implementing closer valve spacing on certain pipelines….Numerically, only 5% of the incidents reported to OPS resulted in the loss of the equivalent of more than 10 miles of product, but they represented about 50% of all the operators spill costs. Thus the incidents that represent about half all the spill damages could be influenced with closer valve spacing."

Another factor that may have an influence on the reported data is that many pipeline operators install check valves downstream of river crossings and at locations where pipelines begin their rise to higher elevations. Interestingly, the industry did not until recently consider these valves as block valves even though the purpose for installing them was to prevent back flow releases should a lower elevation pipe rupture. Check valves are quite effective for preventing product release from pipelines because they are automatic requiring no human recognition of the release and no operator response action.

2.9.3 Olympic Pipe Line Company Current Operations and Spill History (Page 2.9-3) Olympic's record for product releases is not as "good" as claimed (See discussion under **PIPELINE RELEASES FROM LIQUID PIPELINES AND CONSEQUENCES**) and appears to be consistent with the industry in general. The types of problems it has experienced indicates deficient construction practices, quality control procedures, employee training, operating procedures, and system design.

2.9.4 Spill Prevention (Page 2.9-6) - Block valves are not a release prevention method; rather they might be a mitigation measure given timely alerting of a release and prompt closure of the valve through remote operation. Particular notice should be given to the proposed spacing of the block valves. Most are spaced at intervals of 10 miles of less which is reasonably close to the 7.5-mile spacing once recommended by the industry B31.4 Code Committee[4] (a mile section of 14-inch pipe contains about 40,000 gallons of product); however, there are eight pipeline sections where valves are spaced more than 10 miles apart with one section (MP 189.15 to MP 231.01) being 41.8 miles between valves.

All of the "methods" cited other than the use of internal inspections are required by Federal regulation. The use of internal inspection equipment is worthy of note since the applicant does not state the type of internal inspection equipment it will use. "Smart pigs" are considered by some to include any device from a caliper tool capable of detecting dents and out-of-round pipe sections to the more sensitive British Gas tool that has numerous capabilities including the ability to detect small cracks in the pipe wall. This spill prevention method as stated has little meaning without specifying which tool and which inspection capabilities will be used. Another factor involving the adequacy of using internal inspection devices is the time delay experienced between performing the inspection and obtaining the analysis of the inspection. Often the pipeline operator is not provided this information for weeks and sometimes months after the inspection is complete.

Table 2.9-3 provides the estimated flow limits for the pipeline and also indicates the location and sizes of meters. Nowhere does the applicant provide information as to the properties, accuracy (including compensation for product pressure, specific gravity of product, and temperatures changes) nor has the applicant stated information on the reliability of meters to

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[4] Pipeline Accident Report—Liquid Propane Pipeline Rupture and Fire, Texas Eastern Products Pipeline Company, North Blenheim, New York, March 13, 1990 (NTSB/PAR-91/01) page 41.

be used. The adequacy of these factors are critical to the system capability for detecting product loss whether due to ruptures, leaks, or other factors.

2.9.5 Spill Detection (Page 2.9-9/21) - This section includes much dialog with little specific information on the capabilities of the applicant's system for promptly detecting leaks/ruptures, identifying the location of detected failures, and rapidly isolating from the pipeline the failed pipe sections so as to minimize the quantity of product released. Paragraph 49 CFR 195.402 addresses generally the fact that an operator must perform some type of monitoring of its pipeline operations. The monitoring may be manual or automatic or a combination of the two. This requirement for monitoring does not incorporate any criteria on time for detection, frequency of monitoring, or sensitivity standards for monitoring performance. The industry code (B-31.4) requires that liquid operators be able to detect operating conditions in certain facilities not equipped to fail safe "by monitoring pressure, temperature, flow, and other appropriate operational data and transmitting this data to an attended location." However, this code does not specify the accuracy, timeliness, of other criteria an operator must meet to satisfactorily meet the objective. Consequently, there is no mandate by Federal regulations or industry code for an operator to install a monitoring system capable of gathering with sufficient sensitivity and frequency the types of data to promptly alert of and identify the location where an out-of-specification operation, such as a line rupture or leakage, is occurring.

The inability of pipeline operators to promptly detect and isolate failed or leaking pipeline segments has long been voiced as a public safety and environmental concern. The need for more effective spill prevention methods for liquid pipelines was recognized by the U.S. Environmental Protection Agency in an April 1983 paper, "Project Summary, Petroleum Pipeline Leak Detection Study." That paper concluded, in part, that "Once a line becomes operational, however, no guidelines or schedules for effective inspection exist for U.S. pipeline systems. Furthermore, state-of-the-art leak detection methods are not commonly used. Even if they were used, most methods are limited in sensitivity, and significant quantities of fluid could be lost before shutdown. The problem becomes particularly critical for certain pipelines such as those with large-diameter lines in which high volumes of oil can be spilled before conventional leak detection systems can detect the leak and initiate shutdown." While the capability for detecting leaks from petroleum pipelines has improved significantly since that 1983 paper, the industry in general has not seen fit to incorporate this type equipment and there are not regulations requiring them to do so.

The NTSB also has voiced concern for the hazardous liquid industry to use improved leak detection methods and rapid shutdown capabilities. In its 1991 report,[5] the NTSB reviewed the control and monitoring capabilities of liquid pipeline systems involved with product release events as well OPS's inaction to require improvements. Based on its review, the NTSB stated "Consequently, the Safety Board believes that the RSPA should act promptly to establish performance standards for required monitoring to provide for the effective, timely detection of product releases and for the identification of the leak areas."

In a later report,[6] the NTSB discussed a SCADA system where the information transmitted to the dispatcher was adequate for alerting a trained dispatcher of an abnormal system condition involving the release of product. The failure of the dispatcher to recognize the abnormal

[5] Id.

[6] Pipeline Accident Report—Highly Volatile Liquids Release From Underground Storage Cavern and Explosion, MAPCO Natural Gas Liquids. Inc, April 7, 1992 (NTSB/PAR-93/01) pp. 61 & 87.

condition was a combination of inadequate training of the dispatcher and a SCADA system display format that did not facilitate ready identification of the problem by the dispatcher. The Safety Board had previously addressed in a recommendation to the RSPA the need for employee training standards, an improvement the RSPA now has in process with final requirements expected to be issued this year. The Safety Board recommended to both the American Petroleum Institute and the American Gas Association to "In cooperation with (each other), develop standards and guidelines for the design and use of graphic information display systems used by dispatchers to control pipeline systems. (Class III, Longer Term Action)(P-93-20 & 22)." No final action has resulted from these safety recommendations and the OPS has not acted to establish performance standards for required monitoring so as to provide for the effective, timely detection of product releases and for the identification of the leak areas. Even if the OPS acts to implement the objectives sought in these safety recommendations, based on past OPS performance, it is far from certain that each objective would be addressed and if addressed, it is uncertain if the OPS's final action would accomplish the objectives sought.

The applicant advises that the system will be continuously monitored and will have the capability of remotely controlling pumps and valves and doing other things. The applicant also notes on page 2.9-10 that should an abnormal condition occur while the pipeline is operating, "alarms will activate **and an investigation will be initiated by system controllers to determine the source of the abnormal condition." (Emphasis added.)** Further under <u>Renton Control Center Monitoring</u>, the applicant states on page 2.9-10 that pipeline pressures, flow rates, and line balances will be monitored and **"Conditions deviating outside of normal (both high and low) operational standards will be immediately investigated. (Emphasis added.)** Both statements make clear that the applicant does not have a monitoring system adequate to alert a controller of ruptures or leaks with sufficient precision to recognize that immediate action should be taken to shut down the pumps, close appropriate remote-controlled valves, and dispatch to the area of release crews to immediately begin actions to minimize the quantity of product released and to begin clean-up operations. Without this capability, all other discussed actions and capabilities are moot.

Furthermore, even accepting the applicant's statement that its leak detection subsystem is capable of detecting leaks of one percent or less of the average pipeline flow rate, the applicant has not provided reliability information for the system to detect such leakage. For example, can it detect the one percent release rate for 99 out of 100 such events or only 50 out of 100 such events. Even if the system has a high reliability for detection, the stated leak detection capability is inadequate as this means that at the peak flow rate it is unlikely that releases from the 14-inch pipeline that are less than 3,150 gallons per hour (75,600 gallons per day or 529,200 gallons per week) are likely to not be detected promptly. For small leaks detected through the input/output comparisons, detection may occur hours or perhaps days later due to the number of input/output comparisons required before a volume considered significant by the applicant occurs that cannot be justified or explained away through other potential system errors.

An additional concern about the monitoring system is that the applicant states that it is capable of detecting and alerting about abnormal conditions while the pipeline is operating and makes no claim as to the system capability to detect a leak or rupture should the pipeline be shutdown but still filled with product. The need to detect ruptures and leaks is equally important during system shutdown periods.

The previously cited 1995 RSPA report on remote control spill reduction technology acknowledges that "The leak detection capabilities of most SCADA systems can be enhanced with additional leak detection software and user interfaces. Field instruments specifically designed for leak detection are also available for SCADA systems, such as acoustic sensors and hydrocarbon sensing cables." While the RSPA report makes clear the need to improve spill mitigation efforts, the OPS has taken no action to implement the report findings nor has OPL proposed to use more sensitive leak detection methods like acoustic sensors and hydrocarbon cable sensing systems.

SECTION 3 OF DRAFT EIS

General - It should be first noted that the risk assessments contained herein are seriously flawed because the applicant has (1) attempted to perform quantitative risk analysis without recognizing the weaknesses in the data bases and (2) used nationwide incident data that includes both non-fuel and fuel transportation data rather than obtaining and using fuel transportation data for the area of interest. Also while the applicant acknowledges that barges are compartmentalized to mitigate the volume of fuel likely to be released as a result of an accident and it acknowledges that barges soon will be required to have double hulls to prevent product releases due to grounding or contact with objects at the bottom of the waterway, the applicant has not acknowledged that a majority (65 percent) of the barge fleet being used to transport hazardous liquid products on the Columbia River already have been replaced with double hull barges. Ignoring double-hulls and compartmentalization, the applicant used in its "no action" evaluations the total release of products for barge accidents. (Page 3-345). Furthermore, much of the other information provided included incorrect assumptions and improper calculations.

Section 3.18.1.2 Existing Risk of Oil Spills, Fires, or Explosions (Page 3-328) - The second paragraph does not discuss what happens when product spills occur underground and addresses only the characteristics of gasoline when spilled above ground. Product spills below ground, especially diesel and jet fuel, will contaminate the soil and can migrate over large areas below ground. Such spills can be far more damaging to the environment and remedying such spills is far more difficult and costly than for gasoline spills above ground. Diesel and jet fuel spills above ground can also migrate into soils and pose significant challenges for removal and clean up.

The applicant, in reporting U.S. Coast Guard statistics for marine operations, provided specific note that 86 percent of the 44 spills tracked were due to human or program error and advised that "the less amount of human involvement in transport, the fewer number of spills. What the applicant did not reveal is that most all pipeline spills investigated by the NTSB included human or procedural error as one of the causative factors.

The need for improved training of pipeline employees as a means for reducing the incident of human error for causing or contributing to the cause of pipeline failures has long been an NTSB objective because "Federal regulations do not specify the qualifications or certification that a pipeline employee must have or the manner in which he must demonstrate proficiency."[17] In the period between 1978 and 1986, the NTSB made 110 safety recommendations calling for improvements in employee training and qualification. Since that time many more similar safety recommendations were made and now it appears that sometime this year the OPS will issue requirements for pipeline employee qualifications. The extent to which this objective will be achieved once the OPS issues its final rule is not known.

The applicant also failed to note the numbers of pipeline spills attributed to human error so that reasonable comparisons could be made with the information provided. A major reason why such data was not provided may be that good data on this subject is not readily available. The OPS does require liquid pipeline operators to determine and report on the primary cause of incidents, but does not require a listing of the factors leading to the cause of accidents; thus a pipe failure due to overpressure more often than not will be reported as "failed pipe" rather than "incorrect employee operation." Even so, a 1996 NTSB report[7] shows that of 742 accidents that occurred from 1986 through 1994, more than 50 (about 7 %) admittedly were primarily due to incorrect employee operation and that on average, more than 650 BBLs (27,300 gallons) of product were released. The total number of accidents and quantity of product released that involved human error is not known, but is far greater than that reported as being the primary cause. For example, accidents reported as "equipment malfunction" can be due to improper assembly after inspection, "pipe failure" may be due to improper design, and "corrosion" can be due to incorrect monitoring or evaluation of corrosion protection systems. The percentage of human or program error pipeline accidents may be more than for marine accidents - but the available data is insufficient for one to make such a comparison.

On page 3-329, the applicant states that the OPL pipeline system has had 42 releases over its 32 year history. Based on the applicant's Table 2.9-1 where it reported only 26 of the 31 product releases it experienced between 3/13/79 and 5/27/97, one should suspect that a greater number of spills have occurred. Also since the applicant failed to include in Table 2.9-1 almost 1/3 of the product it has released during that time frame, it is reasonable to expect that additional unreported quantities of hazardous liquid product have been released into the environment from the OPL pipeline.

Table 3.18-1 Normalized Fatality Rates for Transportation is skewed to favor the applicant through inclusion of data from other transportation systems that do not relate to fuel transportation. An example of the effect is the inclusion of all rail fatalities including those at grade crossings. Grade crossing accidents are primarily due to vehicles driven by chance-takers who attempt to cross railroad tracks before a train that is known to the driver reaches the crossing to block passage. Such accidents include passenger, general cargo, containerized freight, farm to market, and other types of trains none of which are transporting fuels.

A similar observation can be made for the highway rates. The only realistic comparison for developing this type table would have been to use fuel transport vehicle accident data developed on the transportation vehicles now being used to transport the fuel which the applicant seeks to displace or at the least, use data developed within the State of Washington on rail, marine, and highway fuel transport vehicles. Consequently, the applicant's Table 3.18-1 does not reflect reality and does not provide a means for comparing the fatality rates among competing transportation modes.

Another way to look at accident/fatality rates for pipelines is on the basis of accidents/dollar losses/gallons released per mile since the pipeline, "vehicle," does not move and the product does. The problem with this approach is that the data reporting consistency by operators varied

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[7] Pipeline Special Investigation Report, Evaluation of Accident Data and federal Oversight of Petroleum Product Pipelines (NTSB/SIR-96/20).

each year depending on OPS's emphasis on reporting various items, the lack of quality OPS reviews for completeness of filed reports, and the failure of OPS to audit filings by pipeline operators. Because no audit or other evaluation has been performed to document the types and magnitude of errors this data base contains, the data has very limited usefulness for problem identification and use of this data for trend analysis is fraught with numerous potentials for error. Even so, Table 3 provides an idea of how other data analyses might be performed to provide a more definitive view of the potential consequences of hazardous liquid pipeline failures and leaks.

Table 3: Pipeline Failure/$ Property Damage/Product Released Rates

Source: OPS DATA

Year	Miles of PL	Accidents/mi	$ Property Damage/mile	Gallons Released/mi
1986	153,462	.001362	104.44	60.05
1987	125,859	.001883	104.41	104.33
1988	152,547	.001265	212.49	31.46
1989	150,488	.001083	58.57	33.82
1990	149,008	.001208	105.50	15.41
1991	150,425	.001436	251.21	15.57
1992	152,595	.001389	253.29	18.92
1993	165,781	.001387	174.17	14.72
1994	155,208	.001572	363.73	30.40
1995	153,566	.001224	211.76	145.26
1996	154,863	.001259	320.96	20.07
1997	155,140	.001154	320.39	30.29

.3 **Potential Sizes of Releases to the Environment (Page 3-331) -** NTSB's 1997 *Evaluation of Accident Data and Federal Oversight of Petroleum Product Pipelines* found from analyzing 742 accidents reported to the OPS, that the average product release was about 29,000 gallons per accident. Table 4 shows the approximate average release per accident cause.

Table 4. Approximate Average Release Per Accident Cause - NTSB 1997 Report

Accident Cause OPS	Barrels Released	Gallons Released
Failed Pipe	1,017	42,700
Outside Force	933	39,200
Corrosion	420	17,600
Failed Weld	700	24,900
Malfunction Equip.	280	8,000
Incorrect Operation	680	28,600
Other	770	32,300

The data from the 1985-1998 reports of liquid pipeline operators to the OPS provide a somewhat different look at potential spill size based on historical records than does the data submitted by the applicant. (NOTE: incidents involving only a loss of product less than 50 BBLs is not required to be reported) The following data, based on 2,497 reports, are tabulated in the same format as the applicants to make comparisons easier:

- ♦ Eleven (11) percent of the incidents resulted in spill volumes of 1 BBL (42 gallons) or less. However 32 percent of these 276 reports listed zero for the quantity of product loss which calls into question the accuracy of those reports.
- ♦ The median spill volume was 150 BBLs (6,300 gallons).
- ♦ Twenty-two (22) percent of the incidents resulted in spill volumes of 10

BBLs (420 gallons) or less.

- ♦ Forty-five (45) percent of the incident resulted in spill volumes of 100 BBLs (4,200 gallons) or less (thus 55 percent of the spills were greater than 100 BBLs [4,200 gallons]).
- ♦ Seventy-six (66) percent of the incidents resulted in spill volumes of 650 BBLs. (27,300 gallons) or less.
- ♦ Eighty-one (81) percent of the incidents resulted in spill volumes of 1,750 BBLs (73,500 gallons) or less.
- ♦ The largest spill volume was 122,000 BBLs (5,124,000 gallons).

It is interesting that the applicant provided a somewhat similar type of presentation on potential spill sizes for highway and pipeline, but did not do so for marine and marine terminal spills or for truck terminal spills. Since the U.S. Coast Guard collects marine spill data, a similar spill distribution should be required. Also interesting is that no time period was identified for the truck release data. Consequently, one does not know whether this data is one year of selected data or historical data for a specific time period.

.6 **Emergency Response Plans (Page 3-333)** - As stated in Section 2.3, the applicant has not developed the OPA 90 required spill response plans for identifying and responding to events that can pose a substantial threat of a worse-case product release. The objective development of this plan should provide more useful information than now included in the application.

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.8 **Monitoring and Detection (Page 3-334)** - While the SCADA system can detect some types of releases from the pipeline, the most important aspect is the time frame and precision of detection - these aspects have not been clearly identified by the applicant. The applicant states that the SCADA system can detect leaks around one percent of the flow rate - meaning at maximum flow a leak of about 3,150 gallons per hour or greater may be detected. It was stated that given an abnormal occurrence such as an imbalance of input versus output, the applicant will immediately initiate an investigation. No information is given as to what is involved in the perceived investigation nor the time that might expire during the investigation before positive action will be taken to stop the release and initiate a response to the leak area. Based on other pipeline operator responses to such events, the time before shutdown and response is likely to be several hours after detection.

Equal or greater concern should be given to the quantity of product that can be released when the volume is below the detection capability of the SCADA system. Because of the leak detection limitations of the pipeline SCADA system, a leak of 1-3,000 gallons per hour may go undetected and not become known until product has polluted the soil sufficient to kill vegetation, fish, and wildlife or has surfaced at a lower elevation making detection by aerial surveillance or public reporting possible. This process may take a week or more and by then ½ million or more gallons of product could have been released. Before this pipeline is permitted to operate, it is clear that a state-of-the-art leak detection subsystem is necessary for general environmental protection and that this leak detection subsystem should be supplemented by additional safeguards such as acoustic sensors, clamp on flow meters, double-wall construction, and/or hydrocarbon cable leak detection systems in urban and environmentally sensitive areas.

The applicant again points up as a leak prevention means the use of a corrosion control system. Again, it is important to note that the applicant has not specified the standards to be used for the design, installation, and monitoring of this system and to note that the applicant does not correctly understand that corrosion control systems only mitigate the damage that can be done by corrosion and thus it should not be considered a means for preventing corrosion. Furthermore, these systems can not mitigate all corrosion mechanisms.

8.2 Environmental Consequences

3.18.2.1 Proposed Petroleum Product Pipeline

Operational Impacts-*Overall Proposal*. (Page 3-335 thru 3-343) - The pipeline is characterized as being a state-of-the-art pipeline when in fact, it is consistent with average construction. At a minimum, a state-of-the-art pipeline would be equipped with an efficient leak detection system, perhaps use double-wall construction through environmentally sensitive areas, and have a control center and monitoring system ergonomically designed so as to enhance attentiveness of controllers and aid in their making prompt accurate recognition of leaks or other abnormal operating conditions. This latter capability is critical due to the fact that controllers generally work irregular 12 hours shifts, usually due to their option and without analysis by the pipeline operator to assess whether such work schedules are detrimental to the controller effectiveness. Additionally, a state-of-the-art operation would likely include periodic close interval (test locations generally at 10-foot or less spacing) or continuous corrosion system monitoring to enable prompt identification of isolated areas not receiving corrosion mitigation.

The applicant contends that the causes of leaks and ruptures of underground pipeline systems are documented, for the most part, by spill reports required by the USDOT's OPS. This statement is in stark contrast to the findings of the NTSB in its 1996 report *Evaluation of Accident Data and Federal Oversight of Petroleum Product Pipelines* and other earlier NTSB reports. In its latest report on the OPS accident data reports, the NTSB found that "Although RSPA's data on hazardous liquid pipeline accidents can be analyzed to determine some general trends and conclusions, the data on hazardous liquid pipelines, as they are currently collected and reported, are not sufficient for RSPA to perform an effective accident trend analysis or to properly evaluate operator performance." The NTSB noted that:

> …it is critical that the accident data base used provide complete data in sufficient detail to show not only the cause of an accident, but also the related factors that could increase or decrease the likelihood of occurrence. For example, RSPA and the industry consider excavation damage to be the leading cause of pipeline accidents, Yet, excavation damage is not specifically indicated on RSPA's accident form in a separate data element. The purpose of damage prevention programs, one-call systems, notifications by excavators, and marking of the pipeline is to prevent excavation accidents. For these data entries to be meaningful, therefore, they must be linked to excavation accidents only. Similarly, more detail about pipe coatings and cathodic protection systems would help to identify why external corrosion failures occur. The accident data base must also indicate the consequences of accidents. The environmental impact should be reported separately, apart from property damage. The depth of the pipeline and the location of the accident (urban versus rural locations) are other factors that have a strong bearing on the consequences of an accident. Data on factors that minimize the consequences of an accident, such as remotely controlled valves, leak detection systems, and emergency flow restriction devices, should also be reported to help assess their

effectiveness."

The NTSB report cited ten recommendations it had made to the OPS between 1978 and 1980 for redesigning and improving its data pipeline collection process and forms - only three of which had been satisfied through OPS actions. In that report, the NTSB made one new recommendation to RSPA (OPS) and reiterated three older unsatisfied recommendations as follows:

P-96-1
Develop within 1 year and implement within 2 years a comprehensive plan for the collection and use of gas and hazardous liquid pipeline accident data that details the type and extent of data to be collected, to provide the Research and Special Programs Administration with the capability to perform methodologically sound accident trend analyses and evaluations of pipeline operator performance using normalized accident data.

P-87-4
Require operators of both gas and liquid transmission pipelines to periodically determine the adequacy of their pipelines to operate at established maximum allowable pressures by performing inspections or tests capable of identifying corrosion-caused and other time-dependent damages that may be detrimental to the continued safe operation of these pipelines and require necessary remedial action.

P-87-5
Establish criteria for use by operators in determining the frequency for performing inspections and tests conducted to determine the appropriateness of established maximum allowable operating pressures.

P-95-1
Expedite requirements for installing automatic- or remote-operated mainline valves on high pressure pipelines in urban and environmental sensitive areas to provide for rapid shutdown of failed pipeline segments.

Based on the above information, it should be apparent that neither the OPS nor the industry has good information on which to determine the real causes of accidents and thus, corrective actions implemented by pipeline operators, while well intended, may not significantly influence the incidence of future pipeline leaks and ruptures nor influence their ultimate outcomes.

Table 3.18-3. U.S. Pipeline Failures by Cause (Page 3.337) - The source of the applicant's table is unknown, but it is purported to be based on OPS incident data. In contrast, data from the OPS records show the following for the same period (1994-1996). Data for 1997 has also been added in a separate column. The categories used are the eight published by OPS; there is no **Material Failure** category. (See Table 5: Reference - Applicant Table 3.18-3.)

Table 5: Reference - Applicant Table 3.18-3

1994-1996 Cause of Spill		Incidents 1994-96	Percent of Total		Incidents 1997	Percent of Total
OPS DATA	OPL DATA		OPS	OPL		

Internal Corrosion		44	7.1		18	10.1
External Corrosion		99	15.8		38	21.2
	Corrosion (Internal & External			23		
Defective Weld		39	6.2		3	1.7
	Weld Failure			6		
Incorrect Operation		45	7.2		11	6.1
	Operator Error			7		
Defective Pipe		34	5.4		11	6.1
	3rd Party Action, including Natural Causes			26		
Outside Damage		159	25.4		41	23
	Material Failure			5		
Equipment Malfunction		33	5.3		7	3.9
Other		173	27.6	33	50	27.9
TOTAL		626	100	100	179	100

Volume of Pipeline Spill - Page 3-339 - The "three phases of spill" omits in Phase 3 the time of release before personnel are on scene and act to stop product flow from the pipeline. A company wishing to prevent product release will have temporary/permanent repair clamps that can be installed over a puncture, corrosion hole, or other small opening in the pipe.

Detection - In looking at the times accorded for detection of various size releases and considering that the pipeline is operating at capacity, there is no basis for the time for detection of releases less than 75 BBLs/hour. The stated system detection capability is for only 1 percent of flow or 75 BBLs/hour. While one might argue that the system will not be operating at capacity for several years in the future, when that time comes the SCADA leak detection capabilities will not have improved unless a more sensitive leak detection subsystem is added. The time for detection of leaks smaller than 75 BBLs/hour will be dependent on sufficient product surfacing to be detected visually, on dead or drying vegetation, or polluting ground water to readily detectable levels by taste or smell. The detection time for these leaks more likely will be either the time between aerial monitoring or the time required to kill vegetation, both of which are considerably longer periods than 10 - 30 hours. Accepting the applicant's time for detection of a full open pipe rupture, then up to 2,250 BBLs (9,450 gallons) of product would be released before detection.

The maximum product release rate of 5 to 10 BBLs per hour for 10 to 14 hours (page 3-340) that the applicant claims before detection is without foundation. Moreover, if the release is occurring in an environmentally sensitive area, 5,000 to 6,000 gallons of diesel and other fuels can do significant and irreparable harm. If the applicant is considering the use of computer volume balancing as the means of detecting these smaller losses, the time for detection may be somewhat reduced; however, the amount of reduction is dependent on how the applicant treats "over and short" measurements and on the maintained accuracy of the meters. Unfortunately, the practice of many operators is to justify small out-of-balance volumes rather than to treat them as releases from the pipeline.

Time to Shut Down the Pipeline - During the time for closing a motor-operated valve, the system operating at maximum flow would release about 600 BBLs (26,250 gallons) or product.

Drain-Down Spillage - While the greatest distance in steep topography in the Cascades may be 13 miles, one section of pipeline is 41.8 miles between valves and no information on the topography of this section is provided.

Based on the above and the applicant's assessments, it is reasonable to expect that ½ million gallons or more hazardous liquid product could be released as a result of a pipe rupture.

RECOMMENDATIONS

1. Due to the numerous inaccuracies shown to be in the application, the application should be found incomplete, defective, and insufficient for further consideration.

1. Disclose all accidents/incidents in which product was released from the existing OPL pipelines.

1. Before further consideration of the proposed pipeline, perform an objective comprehensive qualitative risk assessment of alternatives using statistical data compiled from systems operating in the region of the proposed pipeline, considering only those statistics related to fuel transportation, and giving appropriate consideration to vehicle design compartmentalization and to required vehicle safety improvements.

1. Using double-wall pipe, hydrocarbon sensing cables, acoustic sensors, or other devices singly or in combination, provide a means to minimize the potential for product releases and to immediately alert control center operators of product leaks at stream crossings and other areas defined as environmentally sensitive.

1. Develop and conduct during the life cycle of the pipeline (likely 50 or more years) periodic (no less frequent than every 10 days) shut-in tests using methods adequate to detect a 250 gallon product release.

1. Design, install, and monitor the external corrosion protection system to meet or exceed the National Association of Corrosion Engineers Standard RP0169 requirements.

1. Repair and electrically retest identified pipe and joint coating deficiencies.

1. Perform a baseline internal inspection of the pipeline to serve as a comparative base against future inspections with all inspections being conducted using the full capabilities of British Gas's (or equivalent) internal inspection equipment.

1. Use only pipe manufactured with toughness properties consistent with the prevention of brittle fracture at or below the lowest anticipated environmental or operating temperature for the pipeline.

1. Extend the right-of-way width to be at least 50 feet to provide adequate space for future pipe repairs or modifications and to prevent future damage to adjacent properties.

1. Submit for approval the designs for bridge, rail, water crossing to assure that they are adequate for anticipated wind, suspended weight, and vibration loads.

1. Electrically test all pipe and joint coatings consistent with the corrosion control requirements of NACE Standard RP0169 to assure that the coating provides electrical isolation.

1. Subject the pipeline to hydrostatic test pressures sufficient to strength test the pipe at

100 percent of the theoretical pipe design pressure for a minimum of four hours.

1. Periodically (about every 5 years) reaffirm through pressure tests or comprehensive internal inspections the adequacy of the pipeline for continued safe operation.

1. Install remote or automatic operators on all block (isolation) valves and provide for a maximum 10-mile spacing between valves along the pipeline and install remote or automatic block valves at the high water mark for each water crossing and at the boundary for each wetland crossing.

1. Design all tanks connected to the pipeline system to comply with the U.S. Environmental Protection Agency requirements for petroleum storage tanks.

1. Specify the reliability and performance standards for the control system communication system and design the system to automatically shut down in the event of a control system communication failure.

1. Specify the design, performance, and maintenance standards to which all terminal facilities will comply.

1. Require the applicant to develop, using ergonomic engineering standards, the graphic information SCADA system displays so as to assure that the dispatchers have superior opportunity for promptly identifying events indicating system leaks or ruptures.

1. Provide a SCADA leak detection subsystem capable of detecting a ½ percent of maximum design product flow release which is capable of detecting that release rate for at least 99 out of 100 such events.

1. Develop and implement an internal annual safety audit procedure capable of identifying conditions, procedures, and operations not in compliance with standards, regulations, and application approval conditions and implement a procedure for prompt correction of identified deficient conditions.

1. In addition to compliance with 49CFR195, OPL's design, construction, testing, inspection, operations, and maintenance practices should comply with the documents, standards, and recommended practices listed in Appendix B.

1. Before approval of the application, develop for approval a spill response plan in compliance with OPA 90 requirements including the:

   A. Identification of areas requiring prompt alerting of any product release to minimize environmental damage consequences and specific remedies; and

   A. Identification of events that can pose a substantial threat of a worse-case product release and means for minimizing the potential consequences.

Respectfully submitted,

Charles H. Batten, P.E.
President
Batten & Associates, Inc.

HC 75 Box 2201
140 Edgemont Circle
Locust Grove, Virginia 22508
540-972-2002

APPENDIX A

Examples of Petroleum Product Pipeline Release Consequences

On August 24, 1996, an 8-inch-diameter highly volatile liquids (liquefied petroleum gas [LPG]) pipeline operated by Koch Pipeline Company, LP, ruptured near Lively, Texas, sending a butane vapor cloud into a surrounding residential area. The butane vapor ignited as two area residents in a pickup truck drove into the vapor cloud[1] The two people died at the accident site from thermal injuries, about 25 families were evacuated from the affected area, and the pipeline operator's loss was about $217,000. Other property losses included damage to the roadway, the pickup truck, a mobile home, several outbuildings, and adjacent woodlands. The National Transportation Safety Board (NTSB) determined the probable cause of the accident was the failure of the pipeline operator to adequately protect its pipeline from corrosion. The NTSB also determined that Federal regulations do not contain requirements for determining and subsequently evaluating the coating condition on pipelines. It concluded that because no overall requirement exists for operators to evaluate pipeline coating conditions, problems similar to those that occurred on this pipeline could occur on others. The NTSB iterated previous actions it had taken since 1987 to get the OPS, Federal pipeline safety regulatory agency, to include corrosion protection system criteria in its hazardous liquid pipeline regulations and stated that this accident again demonstrates the continuing need for the OPS to act. Also, the NTSB recommended that the National Association of Corrosion Engineers develop a standard for microbial sampling and testing of external surfaces of underground pipelines.

On June 26, 1996, a 36-inch-diameter Colonial Pipeline Company pipeline ruptured at a corroded section of the pipeline where it crossed the Reedy River at Fork Shoals, South Carolina.[2] The ruptured pipeline released 957,000 gallons of fuel oil into the river and surrounding areas. The estimated cost for the cleanup and settlement with the State of South Carolina was $20.5 million. That cost did not include out-of-court settlements with property owners. The NTSB determined that the probable cause of the rupture was the corrosion-weakened pipe was the failure of the pipeline operator (1) to have adequate management controls in place to protect the corroded pipe; and (2) to ensure that pipeline controllers (operators) were adequately trained to both recognize and respond properly to operational emergencies, abnormal conditions, and pipeline leaks.

Between October 14 and October 21, 1994, rains flood the San Jacinto River near Houston, Texas. During the flooding, 8 pipelines ruptured including three liquid pipelines that released more than 35,000 barrels (1.47 million gallons) of petroleum and petroleum products into the river.[3] Although the weather forecasters daily provided information on the continuing rains and on the water height and velocity (information sufficient to make known the fact that the flood was in excess of the projected 100 year flood), the liquid pipeline operators took no effective action to prevent the release of product into the stream should the pipelines in the flood plain rupture. The released petroleum (crude oil) and petroleum products (diesel fuel and gasoline) flowed with the flood waters resulting in the pollution of houses, water, and soils in flooded neighborhoods and on islands within the area. Both the U.S. Coast Guard and the U.S.

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[1] Pipeline Summary Report—Pipeline Rupture, Liquid Butane Release and Fire, Lively, Texas, August 24, 1996 (NTSB/PAR-98/02/SUM).

[2] Pipeline Accident Report—Pipeline Rupture and Release of Fuel Oil into the Reedy River at Fork Shoals, South Carolina, June 26, 1996 (NTSB/PAR-98/01)

[3] Special Investigation Report, "Evaluation of Pipeline Failures During Flooding and of Spill Response Action, San Jacinto River Near Houston, Texas, October 1994," National Transportation Safety Board, Washington, D.C. 20594, NTSB/SIR-96/04.

Environmental Agency participated in the cleanup of the released petroleum and petroleum products having to halt river vessel traffic and continuing the evacuation of more than 580 people who had been evacuated due to the flood waters. Gasoline and diesel fuels on one of the lakes formed in the river was ignited resulting in thick, black smoke clouds filling the air within the area. Five hundred forty-seven people were treated at four local hospitals for smoke and petroleum fume inhalation. The property losses and emergency response costs resulting from this incident was estimated to be about $25 million.

On March 28, 1993, a 36-inch diameter pipeline transporting diesel fuel under 549 psig pressure ruptured in Reston, Virginia, near the town center.[4] The rupture occurred at a point where the pipe had been mechanically damaged by excavation-type equipment at an undetermined previous time. The geyser of diesel fuel erupting from a 5-foot long opening in the pipe flowed into a nearby run-off pond, then into Sugarland Run Creek, and into the Potomac River. More than 9,708 barrels (407.736 gallons) of diesel fuel were released causing environmental pollution that threatened the water supplies for areas in Virginia, Maryland, and the District of Columbia. The ruptured section of pipeline was not shut-in for 1 hour and 32 minutes after the rupture.

“On January 13, 1992, a spill associated with the Williams Pipeline Company’s (WPL) interstate pipeline running between Sioux Falls, South Dakota and Minnesota was discovered near the community of Renner, South Dakota, which is located approximately three miles northwest of Sioux Falls. The leak was discovered by a farmer who was inspecting his soybean field.”[5] Investigation revealed that more than 200,000 gallons (4762 barrels) of petroleum products (including various grades of gasoline, military jet fuel and heating oil) had leaked from the 8-inch diameter pipeline through a hairline crack that had occurred apparently due to a manufacturing defect in the seam of the pipe. The leak was estimated to have occurred around July 1, 1991, and that about 2 million barrels of product had been pumped through the pipeline since the crack was believed to have initiated. The leaked product amounted to only 0.23% of total product pumped through the 24,000 barrels-per-day pipeline after the crack was believed to have initiated. After the accident, 40 wells were drilled into the soil to aid in the removal of petroleum product from the soils about a large underground aquifer, a close-interval corrosion survey was conducted on the first six miles of the pipeline at a cost of $14,050 (including the area of the crack), the first 17 miles of pipeline (including the area of the crack) was hydrostatically tested without failure to 130% of its normal operating pressure at a cost of $133,249, and the line was inspected at a cost of $233,200 using an internal inspection instrument to locate anomalies in the pipe wall; 15 anomalies requiring repair were found. The crack through which the product leaked from the pipeline had not been discovered in 1987 when the pipeline operator had hydrostatically tested this section of pipeline as a part of its system-wide safety and modernization program nor had the leaked product been detected by it routine air patrol inspections that occurred during the almost seven months before the leak was detected by the land owner. As a part of its settlement, the pipeline operator installed a hydrocarbon sampling tube and analyzer system adjacent to the pipeline segment that crossed the underground aquifer. This system constantly samples the atmosphere of the soil adjacent to the pipeline, determines if hydrocarbons exist in the soil, and alerts the pipeline control center when hydrocarbons are detected. The pipeline company also installed remote-actuated valves

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[4] Pipeline Accident Brief No. DCA93MP007, National Transportation Safety Board, Washington D.C. 20594.

[5] February 5, 1992, letter from Senator Thomas Daschle to Mr. George W. Tenley, Director, Office of Pipeline Safety, U.S. Department of Transportation.

in its pipeline on each end of the aquifer and to limit the quantity of product that can be released into the soil, those valves are closed any time there is an indication of hydrocarbons in the soil adjacent to the pipeline segment crossing the aquifer.

On December 19, 1991, a 36-inch diameter pipeline ruptured in a stream at a golf course near Simpsonville, South Carolina releasing diesel fuel into Durbin Creek and resulting in environmental pollution in 26 miles of waterway, including the Enoree River which flows through Sumpter National Park.[6] Pollution of the waterway resulted in the towns of Clinton and Whitmore shutting down their water supplies causing them to bring in alternative water supplies for their citizenry. The rupture was caused by mechanical damage inflicted on the pipe during earlier excavation activities within the river. It took the pipeline company almost 3 hours to locate the site of the release. More than 13,100 barrels (550,200 gallons) of diesel fuel were released. The pipeline controller at the control center in Atlanta, Georgia, observed a sharp drop in pressure readings, shutdown upstream and downstream pumps, and dispatched employees to located the rupture. More than 3 ½ hours later the rupture was located and manual valves were closed to isolate the failed pipeline segment.

On March 30, 1990, near Freeport, Pennsylvania, mixed petroleum products were released to the environment when a shutdown 10-inch pipeline failed during a landslide.[7] The 1,300 barrels (54,600 gallons) of mixed petroleum fuels released from the pipe separation flowed into Knapps Run, then into the Allegheny River, and then into the Ohio River at Pittsburgh. Vessel traffic on the Allegheny River was ceased and for almost a week several downstream communities had to shut down their public water supply systems and transport bottled drinking water for their citizens. It required more than 7 hours for the pipeline operator to locate the point of rupture in the pipeline and to notify environmental response agencies about the release into the rivers. While the reported losses were reported as $14,000,000, it was not possible to determine the losses resulting from disrupting the river vessel traffic and from the loss of drinking water supplies to downstream communities.

On May 25, 1989, a 14-inch diameter CalNev Company petroleum pipeline in at San Bernardino, California within a railroad right-of-way adjacent to a residential development ruptured releasing gasoline.[8] Excavation-type mechanical damage had been inflicted on the pipe metal at an earlier time. Witnesses reported seeing a geyser of liquid shooting into the air, a “white-colored rain” falling in the neighborhood, and then an explosion rocked the neighborhood. Black smoke and flame reaching 10 feet above the roof tops followed the explosion creating intense heat throughout the neighborhood. Two residents were killed, eleven houses and 21 motor vehicles were destroyed, and 7 houses were damaged as a result of the smoke and fire. Seven additional homes would have been destroyed as a result of the pipeline rupture had they not been destroyed 13 days earlier due to a train derailment. Those houses were nearer the pipeline than those destroyed as a result of the pipeline rupture and likely the death toll would have included people in those houses at the time of the pipeline rupture. Property destroyed would likely have been in excess of $3,320,000 in lieu of the $2,310,000 reportedly resulting from the pipeline rupture. Some of the destroyed house were more than 500 feet from the rupture. The pipeline transported gasoline, jet fuel, and diesel fuel.

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[6] Pipeline Accident Brief No. DCA93FP001, National transportation Safety Board, Washington, D.C. 20594.

[7] Pipeline Accident Brief No. DCA90FP009, National Transportation Safety Board, Washington, D.C. 20594

[8] Railroad Accident Report, “Derailment of Pacific Transportation Company Freight Train on May 12, 1989 and Subsequent Rupture of Calnev Petroleum Pipeline on May 25, 1989, San Bernardino, California,” National Transportation Safety Board, Washington, D.C., NTSB/RAR-90/02.

At the time of the rupture, the pipeline was operating at 1,620 pounds per square inch (psig) pressure and transporting about 2,400 bph (100,800 gallons per hour) of gasoline.

On February 16, 1987, Williams Pipe Line Company (WPL) reported to the National Response Center that about 715 barrels (30,030 gallons) of petroleum product had leaked from its terminal facility at Sioux Falls, South Dakota, resulting in about $4 million in property damage.[9] In that report the pipeline operator advised that its 12th Street terminal was converted from JP-4 fuel service to unleaded gasoline in September 1985 and that during filling operations on September 22 and 23, 1985, a small and undetected corrosion leak developed in the tank bottom. The leak was not detected until a resident east of the tank farm reported on May 30, 1986 that she smelled the odor of gasoline in her basement. At that time, the storage tank was emptied and a small corrosion hole was found in the tank bottom. The tank was fitted with a fiberglass bottom and returned to service. On September 17, 1986, the odor of gasoline was observed at an elementary school south of the tank farm. Site investigations performed by a consultant from September 18, 1986 through February 15, 1987, indicated that the leaking tank was the source of the gasoline vapors and that 10,000 gallons of gasoline were in the soil beneath the resident's house and that about 20,000 gallons of gasoline were under the school site. Several additional releases of petroleum product occurred from WPL facilities in the Sioux Falls area in 1987 and citizens and pipeline employees made public allegations questioning the pipeline company dedication to safely operating its pipelines. This resulted in the U.S. Senator from that area writing to the Director of the OPS requesting an investigation into those releases and allegations. An investigation by the Office of Inspector General of the U.S. Department of Transportation and a hearing by the OPS found that pipeline operator failed to report the May 30, 1986 product release and failed to timely report a March 11, 1987 release, failed to adhere to its own procedures on tank inspections, either failed to inspect and test thermal relief valves or failed to keep records of the required tests, and failed to provide over pressure protection of its pipelines. The OPS assessed fines against the pipeline operator in the amount of $59,000. In addition to the OPS assessment, on November 21, 1988, the State of South Dakota and the City of Sioux Falls entered into a settlement agreement for about $271,000 as well as establishing numerous requirements for product removal and cleanup and requiring agreement on an extensive soil testing and monitoring program to assure that the environment was cleaned of petroleum product contaminates.

On January 5, 1987, at Centerville, Virginia, a rock ripper punctured a 32-inch diameter pipeline buried 38 inches deep in a residential community.[10] The pipeline location was clearly marked and visible to the machine operator and a pipeline employee was in the residential community at the time of the rupture. Gasoline under 190 psig pressure and a flow rate through the pipeline of 14,300 barrels per hour sprayed from the puncture into the air drenching 6 townhouses and an adjacent wooded area, but was not ignited. Gasoline flowed into storm drains that led to filtration ponds where the 370 barrels (15,540 gallons) of gasoline were contained. Responding fire departments evacuated the 150 construction workers in the area and 284 adjacent residential houses. There were no fatalities, but 13 people were injured and the monetary loss to the community and the pipeline was about $1,000,000. The gasoline also damaged trees, lawns, soils, shrubbery, and several vehicles.

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[9] National Response Center "Accident Report-Hazardous Liquid Pipeline, No. 870070."

[10] Pipeline Accident Brief No. DCA87FP011, National Transportation Safety Board, Washington, D.C. 20594

On July 7, 1986, at Moundsview, Minnesota, an 8-inch diameter pipeline transporting gasoline under 1,290 psig pressure ruptured in a residential street.[11] Gasoline being transported through the pipeline at a rate of 965 bph (40,530 gallons per hour) sprayed into the air and flowed along neighborhood streets for more than a city block into storm drains, and into a shallow aquifer until ignited 20 minutes after the rupture. Flames spread along the path of the gasoline killing two people, injuring three others, and damaging 25 houses. Environmental damage consisted of killing about 600 fish and animals and contaminating the ground water aquifer. The pipeline company estimated that 30,000 gallons of gasoline were released even though the pipeline had been shutdown about 5 minutes after the rupture occurred. The pipe had ruptured at a longitudinal weld seam that had not been fully fused during its manufacture. After this accident the pipeline company made many modifications to its pipeline system and its operating procedures most of which are not required by Federal safety regulations. It modified its cathodic protection program, retrained its personnel on using remote-operated valves and closing all stations valves when a product release is suspected, revised its emergency response procedures, development computer-based training modules for training and testing its employees on required work tasks, revised its operating procedures for pipelines in urban areas, developed emergency response preparedness plans in coordination with local agencies, and initiated a plan to install remote-operated valves in its pipelines within highly populated areas.

On July 23, 1985, about 8 miles south of Kaycee, Wyoming, an 8-inch-diameter petroleum products pipeline cracked at a girth weld while the pipeline company was recoating the pipe.[12] Aircraft turbine fuel was released under 430 psig pressure atomizing into the air until ignited. An estimated 1,074 barrels (45,108 gallons) of JP-4 fuel was released and consumed in the fire during the 35 minutes after the release before one of the employees at the accident scene was able to obtain use of a two-way radio to tell the dispatcher at the control center to shut the pipeline down. The release had not been detected at the control center. The resulting fire killed one person, injured six others, destroyed construction equipment, and caused the shut down of pipeline operations. Damage was estimated at more than $128,000 even thought the accident occurred in a remote and uninhabited area.

At 10:35 a.m. on June 19, 1985, a 12-inch-diameter Explorer Pipeline Company products pipeline near Addison, Texas, buried 6 feet below ground was ruptured by a backhoe.[13] The pipeline was well marked and both contractor and the drainage engineers were aware of the general location of the pipeline. During the excavation, the pipeline became visible to the backhoe operator. He struck and gouged the pipeline three times before the backhoe bucket punctured it. Unleaded gasoline under 560 psig pressure sprayed into the air and into a nearby stream from the 3-inch by 7-inch triangular puncture. The released product was ignited and burned until 4 p.m. even though the pipeline operator had closed manual valves on each side of the rupture to isolated the failed pipeline to a 4-mile section. One person received burn injuries and the front wall of an adjacent 4-story building was substantially burned. In addition to the pipeline and environmental damages, damages to adjacent buildings was estimated to be $300,000.

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[11] Pipeline Accident Report, "Williams Pipe Line Company Liquid Pipeline Rupture and Fire, Mounds View, Minnesota, July 8, 1986," National Transportation Safety Board, Washington, D. C. 20594, NTSB/PAR-87/02.

[12] Pipeline Accident Report, "Continental Pipe Line Company Pipeline Rupture and Fire, Kaycee, Wyoming, July 23, 1985," National Transportation Safety Board, Washington, D.C., NTSB/PAR-86/01.

[13] Pipeline Accident Brief, Explorer Pipeline Company Pipeline Rupture and Fire, June 6, 1985, Addison, Texas, National Transportation Safety Board, Washington, D.C., DCA-85-FP-013.

On December 1, 1980, at Long Beach, California, an 8-inch diameter pipeline being operated improperly ruptured beneath city streets and naphtha under 800 psig pressure sprayed 20 feet into the air and flowed into street gutters until it was ignited moments later.[14] The ensuing flames reached a height of 70 feet destroying one house and 11 vehicles, damaging 11 other houses, and killing 5 people. The failed section of pipeline was not shutdown until 2 hours and 40 minutes after the rupture which prolonged the fire and hampered fire fighting actions.

On March 6, 1980, a 32-inch diameter petroleum products pipeline ruptured in two locations; one near Manassas, Virginia, and the other at Locust Grove, Virginia.[15] At Manassas, the pipe wall had been thinned by corrosion in a casing beneath a road causing the pipe to break and release 8,000 barrels (336,000 gallons) of aviation-grade kerosene which flowed into Bull Run River and entered the Occoquan Reservoir, a source of drinking water for several northern Virginia communities. Simultaneously, a crack in a pipe wall near Locust Grove, Virginia, propagated to failure releasing 2,190 barrels (91,980 gallons) of No. 2 fuel oil. The released fuel oil flowed into the Rapidan River and then into the Rappahannock River, a source of drinking water for the City of Fredericksburg, Virginia. While there was no ignition of the released fuels and no person was killed, 10,000 to 15,000 fish and some small animals and waterfowl were killed, the rivers, the reservoir, and their banks were contaminated, farm lands were contaminated, and communities were without drinking water. The cleanup continued for several months after the accidents and cost in excess of $1,000,000.

On January 30, 1980, an 8-inch diameter refined petroleum products pipeline was ruptured by a bulldozer while working on a water line.[16] Gasoline sprayed under 300 psig pressure from the pipeline running downhill and into a small creek that ran into an underground canal beneath residential buildings and beyond into an open canal that divides part of two residential districts. The gasoline continued to spray for 1 ½ hours from the ruptured pipe before it exploded and ignited killing one person and destroying property on each side of the canal and creek. About 1,850 barrels (77,700 gallons) of gasoline burned as did 25 adjacent houses and vegetation.

On June 16, 1976, at Los Angeles, California, an 8-inch diameter petroleum products pipeline was struck and ruptured by excavation equipment.[17] Gasoline sprayed from the rupture drenching nearby commercial buildings until it was ignited 90 seconds after the rupture. The ensuing fire filled 9 people, injured 14 others, destroyed 16 commercial buildings, and destroyed 15 vehicles that were either traveling on or parked in the median of Venice Boulevard. The intense heat from the fire melted power and communication lines.

On September 2, 1970, at Jacksonville, Maryland, a 30-inch diameter petroleum products pipeline leaked gasoline from flaw in the pipe metal, flowed south for about 300 feet to a small creek where its odor was detected by a resident.[18] The resident telephoned the pipeline

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14 Pipeline Accident Report, “Four Corners Pipe Line Company Pipeline Rupture and Fire, Long Beach, California, December 1, 1980, National Transportation Safety Board, Washington, D.C. 20594, NTSB/PAR-81/04.

15 Pipeline Accident Report, Colonial Pipeline Company Petroleum Products Pipeline Failures Manassas and Locust Grove, Virginia, March 6, 1980,” ,” National Transportation Safety Board, Washington, D.C. 20594, NTSB/PAR-81/02.

16 Pipeline Accident Report, The Pipelines of Puerto Rico, Inc. Petroleum Products Rupture and Fire, Bayamon, Puerto, Rico, January 30, 1980,” National Transportation Safety Board, Washington, D.C. 20594, NTSB/PAR-80/06.

17 Pipeline Accident Report, “Standard Oil Company of California Pipeline Rupture, Los Angeles, California, June 16, 1976,” National Transportation Safety Board, Washington, D.C. 20594, NTSB/PAR-76/08.

18 Pipeline Accident Report, “Colonial Pipeline Company Petroleum Products Pipeline, Jacksonville, Maryland, September 3, 1970,” National Transportation Safety Board, Washington D.C. 20594, NTSB/PAR-71/2. September 8, 1995, Deposition, Gordon H. Harris, Esquire, p22.

company notifying it of the gasoline odors. Pump stations upstream and downstream of the leak were shutdown -the pump stations were 195 miles apart. Pipeline personnel arrived in the area of the product release about 40 minutes after the leak was reported and they proceeded to close manual line block valves upstream and downstream of the leak area. It took the pipeline employees about 20 minutes to close the manual line block valves. This isolated the leak within a 4-mile segment of the pipeline. Contractor personnel were dispatched to locate the leak. Almost 24 hours after the leak was reported to the pipeline operator and while contractor personnel were manually excavating an area to help contain the leaking gasoline, and explosion and flash fire occurred and five men were burned. Four days later the leak was located and the pipe flaw was repaired. Before and at the time of the release, the pipeline was transporting products at about the maximum capacity of the line, 32,000 barrels per hour. The turbine-type meters used to measure the product flow were considered accurate to within 0.5 percent of product volume flowing, but had not detected the loss of 718 barrels (30,156 gallons) of gasoline and kerosene that had been released.

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49 CFR 195.210(a)

Special Report 219, "Pipelines and Public Safety," Transportation Research Board, National Research Council, 1988, pp. 65-67.

Special Report 219 "Pipelines and Public Safety," Transportation Research Board, National Research Council, 1988.

"Safety Report on the Progress of Improvements in Pipeline Transportation of Highly Volatile Liquids," (NTSB/SR-79/03) National Transportation Safety Board, Washington, D.C. 20594, September 28, 1979.

Special Report 219, "Pipelines and Public Safety," Transportation Research Board, National Research Council, 1988, pp. 65-67.

Pipeline Accident Report, " Texas Eastern Transmission Corporation Natural Gas Pipeline Explosion and Fire, Edison, New Jersey, March 23, 1994," National transportation Safety Board, Washington, D.C. 20594 (NTSB/PAR-95/01) p. 67.

"The Safety of Interstate Liquid Pipelines; An Evaluation of Present Levels and Proposals for Change," Research Study #040, American Petroleum Institute, 1220 L. Street, Northwest, Washington, D.C. 20005, July 1987.

NTSB/PAR-82/03; NTSB/PAR-87/02; NTSB/PAR-88/01; NTSB/PAR-90/01; NTSb/SIR-96/02; NTSB/SIT-96/04.

Pipeline Accident report, "San Juan Gas Company, Inc/Enron Corp. Propane Gas Explosion in San Juan, Puerto Rico, on November 21, 1996," National Transportation Safety Board, Washington, D.C. 20594 (NTSB/PAR-97/01) p. 59.

Pipeline Accident Report, "Mid-America Pipeline System Liquefied Petroleum Gas Pipeline Rupture, West Odessa, Texas, March 15, 1983," National Transportation Safety Board, Washing ton, D.C. 20594, (NTSB/PAR-84/01).

Special Report 219, "Pipelines and Public Safety," Transportation Research Board, National Research Council, Washington, D.C., 1988.

Pipeline Accident Report, "Texas Eastern Transmission Corporation, Natural Gas Pipeline Explosion and Fire, Edison, New Jersey, March 24, 1994," National Transportation Safety Board, Washington, D.C. 20594 (NTSB/PAR-95/01).

Special Investigation Report, "Evaluation of Pipeline Failures During Flooding and of Spill Response Action, San Jacinto River Near Houston, Texas, October 1994," National Transportation Safety Board, Washington, D.C. 20594, NTSB/SIR-96/04.

Pipeline Accident Brief No. DCA93MP007, National Transportation Safety Board, Washington D.C. 20594.

February 5, 1992, letter from Senator Thomas Daschle to Mr. George W. Tenley, Director, Office of Pipeline Safety, U.S. Department of Transportation.

Pipeline Accident Brief No. DCA93FP001, National transportation Safety Board, Washington, D.C. 20594.

Pipeline Accident Brief No. DCA90FP009, National Transportation Safety Board, Washington, D.C. 20594

Railroad Accident Report, "Derailment of Pacific Transportation Company Freight Train on May 12, 1989 and Subsequent Rupture of Calnev Petroleum Pipeline on May 25, 1989, San Bernardino, California," National Transportation Safety Board, Washington, D.C., NTSB/RAR-90/02.

National Response Center "Accident Report-Hazardous Liquid Pipeline, No. 870070."

Pipeline Accident Brief No. DCA87FP011, National Transportation Safety Board, Washington, D.C. 20594

Pipeline Accident Report, "Williams Pipe Line Company Liquid Pipeline Rupture and Fire, Mounds View, Minnesota, July 8, 1986," National Transportation Safety Board, Washington, D. C. 20594, NTSB/PAR-87/02.

Pipeline Accident Report, "Continental Pipe Line Company Pipeline Rupture and Fire, Kaycee, Wyoming, July 23, 1985," National Transportation Safety Board, Washington, D.C., NTSB/PAR-86/01.

Pipeline Accident Brief, Explorer Pipeline Company Pipeline Rupture and Fire, June 6, 1985, Addison, Texas, National Transportation Safety Board, Washington, D.C., DCA-85-FP-013.

Pipeline Accident Report, "Four Corners Pipe Line Company Pipeline Rupture and Fire, Long Beach, California, December 1, 1980, National Transportation Safety Board, Washington, D.C. 20594, NTSB/PAR-81/04.

Pipeline Accident Report, Colonial Pipeline Company Petroleum Products Pipeline Failures Manassas and Locust Grove, Virginia, March 6, 1980," ," National Transportation Safety Board, Washington, D.C. 20594, NTSB/PAR-81/02.

Pipeline Accident Report, The Pipelines of Puerto Rico, Inc. Petroleum Products Rupture and Fire, Bayamon, Puerto, Rico, January 30, 1980," National Transportation Safety Board, Washington, D.C. 20594, NTSB/PAR-80/06.

Pipeline Accident Report, "Standard Oil Company of California Pipeline Rupture, Los Angeles, California, June 16, 1976," National Transportation Safety Board, Washington, D.C. 20594, NTSB/PAR-76/08.

Pipeline Accident Report, "Colonial Pipeline Company Petroleum Products Pipeline, Jacksonville, Maryland, September 3, 1970," National Transportation Safety Board, Washington D.C. 20594, NTSB/PAR-71/2.

APPENDIX B

Recommended Standards and Practices in Addition to Federal Requirements (Latest known dates shown, otherwise latest edition should be used)

1. American Concrete Institute (ACI), ACI Standard 201.2R-77(82), Guide to Durable Concrete, Sixth Printing, 1982
2. ACI Standard 222R-89, Corrosion of Metals in Concrete, 1989
3. ACI Standard 224R-89, Control of Cracking in Concrete Structures, 1989
4. ACI Standard 318-89/318R-89, Building Code Requirements for reinforced Concrete and Commentary, 1989
5. ACI Standard 350R-89, Environmental Engineering Concrete Structures ACI 515R.1R Guide to the Use of Waterproofing, Dampproofing, Protective and Decorative Barrier Systems for Concrete, 1989
6. ANSI/ASME Boiler and Pressure Vessel Code, Section Heating Boilers including non-mandatory Appendices A, B, C, D, E, F, H, I, and J and the Guide to Manufacturers Data Report Forms, 1989
7. ANSI/B1.1 Unified Screw Threads
8. ANSI/ASME B1.20 Pipe Threads, General Purpose
9. ANSI/ASME B16.3 Malleable Iron Threaded Fittings
10. ANSI/ASME B16.4 Gray Iron thread Fittings
11. ANSI/ASME B16.9 Factory-Made Wrought Steel Buttwelding Fittings
12. ANSI/ASME B16.11 Forged Fittings, Socket-Welding and Threaded
13. ANSI/ASME B16.22 Wrought Copper and Copper Alloy Solder-Joint Pressure Fittings
14. ANSI/ASME B16.14 Ferrous Pipe Plugs, Bushings and Locknuts with Pipe Threads
15. ANSI/ASME B16.15 Cast Bronze Threaded Fittings
16. ANSI/ASME B16.20 Metallic Gaskets for Pipe Flanges - Ring Joint, Spiral Wound and Jacketed
17. ANSI/ASME B16.25 Buttwelding Ends
18. ANSI/ASME B16.28 Wrought Steel Buttwelding Short Radius Elbows and Returns
19. ANSI/ASME B16.34 Valves - Flanged, Threaded, and Welding End
20. ANSI/ASME B16.47 Large Diameter Steel Flanges
21. ANSI B16.18 Cast Copper Alloy Solder Joint Pressure Fittings
22. ANSI B18.2.1 Square and Hex Bolts and Screws
23. ANSI/ASME B18.2.2 Fastners: quare and Hex Nuts
24. ANSI B31.1, Pressure Piping Code, Power Piping, and Addenda B31.1a, 1989
25. ANSI/ASME B31.3 Process Piping
26. ANSI B31.4, Liquid Transportation Systems for Hydrocarbons, Liquid Petroleum Gas, Anhydrous Ammonia and Alcohols, 1992
27. ANSI/ASME B31.9 Building Services Piping Code
28. ANSI B16.1, Cast-Iron Pipe Flanges and Flanged Fittings, 1977
29. ANSI B26.5, Steel Pipe Flanges and Flanged Fittings, 1977
30. ANSI B120.3 Dryseal Pipe Threads
31. ANSI C1, National Electric Safety Code, 1975
32. American Petroleum Institute (API) Chapter 6.6, Manual of Petroleum Measurement Standards, Metering Assemblies, Pipeline Metering Systems, First Edition, 1981, Reaffirmed August 1987 (ANSI/API MPMS 5.6-1981)
33. API Publication 2008, Safe Operation of Inland Bulk Plants (1984)
34. API Publication 2200-83, Repairing Crude Oil, Liquefied Natural Gas, and Product Pipelines (1983)
35. API Recommended Practice 12R1 (RP12R1), Recommended Practice for Setting, Maintenance, Inspection, Operation, and Repair of Tanks in Production Service, Fourth Edition, 1991
36. API Recommended Practice 500 Classification of Locations for Electric Installations at Petroleum Facilities
37. API Recommend Practice Sizing, Selection and Installation of Pressure Relieving Devices in Refineries
38. API Recommend Practice 521, Guide for Pressure-Relieving and Depressuring Systems, Second

Edition, September 1982
39. API Recommend Practice 652, Lining of Aboveground Petroleum Storage Tank Bottoms, First Edition, 1991
40. API Recommended Practice 1102, Recommended Practice for Liquid Petroleum Pipelines Crossing Railroads and Highways, Fifth Edition, November 1981 and Errata
41. API Recommended Practice 1107, Recommended Practice for Pipeline Maintenance Welding Practices, Section 7, Repair or Removal of Defects
42. API Recommended Practice 1110, Recommended Practice for the Pressure Testing of Liquid Pipelines, Second Edition, December 1981
43. API Recommended Practice 1117 Movement of In-Service Pipelines
44. API Recommended Practice 2003, Protection Against Ignitions Arising out of Static, Lightning, and Stray Currents, Fourth Edition, March 1982
45. API Recommended Practice for Cathodic Protection of Underground Petroleum Storage Tanks and Pipeline Systems, Second Edition (1987) and Supplement 2, March 1989
46. API Specification 5L, Specification for Line Pipe, 1992
47. API Specification 12 D, Specification for Field Welded Tanks for Storage of Product Liquids, Ninth Edition, January 1982, Supplement 1, March 1983, Supplement 2, May 1985
48. API Standard 5B Threading, Gaging and Thread Inspection of Casing, Tubing and Line Pipe Threads
49. API Standard 510, Pressure Vessel Inspection Code: Maintenance, Inspection, Rating, Repair, and Alteration, Sixth Edition, June 1989, Erratum September 1989
50. API Standard 526, Flanged Steel Safety Relief-Valves, Third Edition, February 1984
51. API Standard 600 Steel Gate Valve-Flanged and Buttwelding Ends
52. API Standard 620, Design and Construction of Large Welded. Low-Pressure Storage Tanks, Eighth Edition, June 1990
53. API Standard 650, Welded Steel Tanks for Oil Storage, Eight Edition, November 1988, Revised 1990
54. API Standard 653, Tank Inspection, Repair, Alteration, and Reconstruction, First Edition, 1991, and Supplement 1, January 1992
55. API Standard 1104, Welding of Pipeline and Related Facilities, Seventeenth Edition, September 1988 and Errata June 1989
56. API Standard 2000, Venting Atmospheric and Low Pressure Storage Tanks, Third Edition, Revised 1987
57. American Society of Mechanical Engineers (ASME), ASME B31.2 Fuel Gas Piping
58. ASME Boiler and Pressure Vessel Code, Section I, Power Boilers, 1992 with Interpretations
59. ASME Boiler and Pressure Vessel Code, Section VIII, Pressure Vessels, Division 1, 1992 with Interpretations
60. ASME Boiler and Pressure Vessel Code, Section VIII, Pressure Vessels, Division 2, Alternative Rules, 1992 with Interpretations
61. ASME Boiler and Pressure Vessel Code, Section IX, Welding and Brazing Qualifications, 1992 with Interpretations
62. American Society for Testing and Materials (ASTM), ASTM A-36 Structural Steel
63. ASTM Specification A69 1 Rev. A, Standard Specification for Carbon and Alloy Steel Pipe, Electric-Fusion Welded for High Pressure Service at High Temperatures, 1989
64. ASTM A 105 Forgings, Carbon Steel, for Piping Construction
65. ASTM A 181 Forgings, Carbon Steel for General Purposes
66. ASTM A 182 Forged or Rolled Alloy-Steel Pipe Flanges, Forged Fittings, and Valves and Parts for High-Temperature Service
67. ASTM A 193 Alloy Steel and Stainless Steel Bolting Materials for High -Temperature Service
68. ASTM A 194 Carbon and Alloy Steel Nuts and Bolts for High pressure and High-Temperature Service
69. ASTM A 234 Piping Fittings of Wrought Carbon Steel and Alloy Steel for Moderate and Elevated Temperatures
70. ASTM A 307 Carbon Steel Bolts and Studs, 60,000 PSI Tensile Strength
71. ASTM A 320 Alloys - Steel Bolting Materials for Low-Temperature Service
72. ASTM Specification A333/A333M, Standard Specification for Seamless and Welded Steel Pipe for Low-Temperature Service, 1991a
73. ASTM A 350 Forgings, Carbon and Low-Alloy Steel, Requiring Notch Toughness Testing for Piping Components
74. ASTM A 420 Piping Fittings of Wrought Carbon Steel and Alloy Steel for Low-Temperature Service

75. ASTM A 449 Quenched and Tempered Alloy Steel Bolts and Studs
76. ASTM Specification A671, Standard Specification for Electric-Fusion-Welded Steel Pipe for Atmospheric and Lower Temperatures, 1989a
77. ASTM E 84 Test Method for Surface Burning Characteristics of Building Materials
78. ASTM A 733 Welded and Seamless Carbon Steel and Austenitic Stainless Steel Pipe Nipples
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82. MSS SP-58 Pipe Hangers and Supports – Materials, Design and Manufacture
83. MSS SP-69 Pipe Hangers and Supports – Selection and Application
84. MSS SP-70 Cast-Iron Gate Valves, Flanged and Threaded Ends, 1976
85. MSS SP-71 Cast-Iron Swing Check Valves, Flanged and Threaded Ends, 1976
86. MSS Sp-75 High Test Wrought Butt Welding Fittings
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91. NACE RP 0175-75, Control of Internal Corrosion in Steel Pipelines and Piping Systems
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NOTE: The above list does not include references in 49CFR195 unless a later edition is available. Other documents listed were obtained from 49CFR192, the Alaska Oil & Hazardous Substances Pollution Control Regulations, and the Guide for Gas Transmission and Distribution Piping Systems ANSI Z380.1 (1998-2000)